Direct Testimony and Schedules
Christopher J. Barthol

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Gas Service in Minnesota

Docket No. G002/GR-23-413
Exhibit___(CJB-1)

Class Cost of Service Study and Decoupling

November 1, 2023

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Christopher J. Barthol. I am a Rate Consultant for Northern States Power Company – Minnesota (NSPM or the Company), d/b/a Xcel Energy.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of the Company.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include 12 years of regulatory experience in the areas of rate design and class cost of service. I have served as a witness before the Minnesota Public Utilities Commission (Commission) and the North Dakota Public Service Commission. I have a Bachelor of Arts in Economics from Saint Cloud State University and a Master of Science in Agricultural Economics from Purdue University. A detailed statement of my qualifications and experience is provided in Exhibit___(CJB-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present the Company's Class Cost of Service Study (CCOSS) and proposed continuation of our Revenue Decoupling Mechanism (RDM).

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED CCOSS.

A. The CCOSS is done on a forecasted 2024 calendar year embedded cost basis, which, based on cost-causation principles, functionalizes, classifies, and allocates budgeted plant and expenses in the 2024 test year. Other than the refinement of the calculation of certain allocators, the Company is proposing only one change to the CCOSS methodology used in the Company's last natural gas rate case, Docket No. G002/GR-21-678. Below, I will describe the modifications to the class allocations and the rationale for the adjustments, detail the class allocations indicated by the CCOSS, and discuss the results of the CCOSS.

II. CCOSS OVERVIEW

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I describe the purpose of the CCOSS that was conducted, and the Company's objectives in conducting the CCOSS. I also summarize the results of the CCOSS.

A. CCOSS Purpose

Q. WHAT IS THE PURPOSE OF A CCOSS?

A. The CCOSS allocates the total cost of providing utility service (also referred to as the Company's revenue requirement) to our various customer classes in a way that reflects the engineering and operating characteristics of the natural gas utility system, and hence each class's contribution to the Company's costs of providing gas service as required by Minn. R. 7825.4300, Subp. C. The primary objective of the CCOSS is to determine the total cost of service for each customer class, which, given the characteristics of gas utility costs, includes the costs associated with investment in plant as well as operation and maintenance (O&M) expenses. Another key objective of the CCOSS is to develop class cost allocation factors that accurately reflect cost causation. Results from the CCOSS serve as a guide for evaluating and developing the Company's rate design, as discussed in more detail by Company witness Michelle M. Terwilliger.

Q. WHAT ARE THE COMPANY'S OBJECTIVES WHEN DEVELOPING ITS CCOSS?

A. The Company's CCOSS objectives are:

1. Properly reflect all the costs and revenues that have been identified in the Company's Minnesota Jurisdictional Cost of Service Study (JCOSS);
2. Develop allocators that can be accurately determined and calculated with a reasonable amount of effort to properly assign those costs among the various customer classes and the three main billing classifications – customer, demand, and commodity; and
3. Use allocators that are consistent across the Company's jurisdictions.

B. CCOSS Results

Q. PLEASE SUMMARIZE THE RESULTS OF THE COMPANY'S PROPOSED CCOSS.

A. The classes in the CCOSS include:

- Residential (Res);
- Commercial (Com) – Small and Large Commercial customers;
- Demand – Small and Large Demand-Billed customers;
- Interruptible (Interrupt) – Small, Medium, and Large Interruptible customers;
- Transportation (Tran) – Firm, Interruptible, and Negotiated Transportation customers; and
- Generation (Gener) – Electric Generation customers who take service on our sales or transportation service tariffs noted above.

Table 1 below shows a summary of the CCOSS results at the major class level. A more detailed summary is provided in Exhibit___(CJB-1), Schedule 3. These results indicate the level of rate increase necessary for each class of service to produce equal rates of return from each class.

Table 1
Summary of Class Cost of Service Study ($000)

Item	Res	Com	Demand	Interrupt	Tran	Gener	Total
CCOSS Results	$410,438	$181,246	$19,423	$35,455	$7,305	$22,964	$676,832
Present Revenue	$364,900	$179,310	$19,847	$37,592	$7,374	$8,783	$617,806
Revenue Deficiency	$45,538	$1,936	-$423	-$2,137	-$69	$14,181	$59,026
Deficiency/Pres	12.48%	1.08%	-2.13%	-5.68%	-0.94%	161.45%	9.55%

Q. PLEASE EXPLAIN THE CCOSS RESULTS SHOWN IN TABLE 1.

A. The CCOSS indicates a cost-of-service increase of 12.48 percent for Residential Firm service, 1.08 percent for Commercial customers, and 161.45 percent for Generation customers. The CCOSS indicates a decrease in the costs of service of 2.13 percent for Demand customers, 5.68 percent for Interruptible customers, and 0.94 percent for Transport customers. As I mentioned above, the CCOSS results serve as a guide for developing revenue apportionment and rate design, as discussed in more detail by Company witness Terwilliger.

Q. HOW DO THE CCOSS RESULTS COMPARE TO THOSE IN THE COMPANY'S LAST NATURAL GAS RATE CASE (DOCKET NO. G002/GR-21-678)?

A. The CCOSS results are similar to the results in the Company's last general rate case in that the Residential and Generation classes' rates are below cost while the Demand, Interruptible, and Transport classes are above cost. The only difference since the last case is that the Commercial class's rates are just below cost whereas they were slightly above cost in the last case. Since our class allocation methodology is similar to the last case, and the approved revenue apportionment in the last case resulted in Residential rates recovering less than the cost of service and other classes recovering more than the cost of service, this result is reasonable. It also should be noted that some customers in the Generation class take service under the flexible rate provisions of our tariffs. Their rates are designed to cover at least incremental costs and not the embedded costs included in the CCOSS.

Q. HOW DO THE CURRENT PRIMARY ALLOCATORS IN THE CCOSS FOR THIS CASE COMPARE WITH THE PRIMARY ALLOCATORS FROM THE CCOSS USED IN THE COMPANY'S LAST NATURAL GAS RATE CASE (DOCKET NO. G002/GR-21-678)?

A. The Company is using the same primary allocators as these allocators continue to be the most appropriate class allocators for assigning costs that vary by customer count, demand (design day), sales, or distribution investment. Table 2 provides a comparison of the primary allocators evaluating their current percentages versus those in the last natural gas rate case. While there are modest changes in these allocators, there are not material changes to the percentages themselves. The Company is however proposing a demand adjustment to its Minimum System Study, which I will explain later. The impact of this adjustment is a cost shift from the Residential class to other classes. This results in a reduction in the "Mains, Overall" percentage for the Residential class and an increase in the class allocators for all other classes. I will explain later in my testimony how these allocators were developed for this CCOSS.

Table 2
Allocator Comparison (2024 TY vs. 2022 TY)

Allocator	Res	Com	Demand	Interrupt	Tran	Gener
Customers - 2024	92.52%	7.39%	0.03%	0.05%	0.01%	0.00%
Customers - 2022	92.40%	7.51%	0.03%	0.06%	0.01%	0.00%
Design Day - 2024	53.13%	30.36%	3.21%	0.00%	0.64%	12.66%
Design Day - 2022	52.55%	31.01%	3.21%	0.00%	0.41%	12.81%
Mains, Overall - 2024	66.77%	19.72%	1.80%	1.66%	2.63%	7.41%
Mains, Overall - 2022	76.34%	15.19%	1.11%	1.20%	1.72%	4.43%
Service Study - 2024	86.69%	12.76%	0.14%	0.37%	0.03%	0.01%
Service Study - 2022	84.76%	14.63%	0.16%	0.41%	0.03%	0.01%
Meter & Regul 2024	80.16%	18.18%	0.57%	0.93%	0.14%	0.03%
Meter & Regul 2022	79.85%	18.10%	0.62%	1.24%	0.15%	0.04%
Sales, W/o Transp - 2024	53.23%	31.76%	3.98%	10.74%	0.00%	0.29%
Sales, W/o Transp - 2022	52.32%	30.91%	4.02%	12.72%	0.00%	0.03%
Sales, W/ Transp - 2024	33.40%	19.93%	2.50%	6.74%	10.34%	27.10%
Sales, W/ Transp - 2022	35.04%	20.70%	2.69%	8.52%	12.04%	21.01%

III. CCOSS PREPARATION

A. Preparation of a CCOSS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I provide an overview of the preparation of the CCOSS and describe the allocators used in the CCOSS.

Q. WHAT TYPE OF CCOSS WAS PREPARED?

A. The CCOSS presented in this case is a fully-distributed, embedded CCOSS. The CCOSS is "fully-distributed" in that it allocates plant and operating expenses based on the manner in which they are incurred. The CCOSS is considered "embedded" because it functionalizes, classifies, and allocates budgeted plant and expenses in the test year.

Q. WHAT ARE THE STEPS FOR PREPARING A CCOSS?

A. In general, preparing a CCOSS involves five major steps:

First, costs are identified by function, such as production, storage, transmission, and distribution. Costs are then separated by state jurisdiction – in this case, between the Minnesota and North Dakota retail gas jurisdictions. This step is supported in the Direct Testimony and Schedules of Company witness Benjamin C. Halama.

Second, costs that can be directly attributed to specific customer classes are directly assigned to their respective classes.

Third, the remaining unassigned costs are allocated among the customer classes by an appropriate allocation method. An external allocator is an allocator that takes information generated separate from the CCOSS, such as a class's sales or customer counts. Internal allocators are based on combinations of costs already allocated to the classes using external allocators. For example, the cost of distribution mains is allocated to a class using an internal allocator that performs calculations relying on a class's contribution to plant in service associated with distribution mains.

Fourth, the costs for each class are then classified as capacity (demand), customer, and commodity (gas) based on whether the costs are driven by Design Day demand, number of customers, or usage. This step guides rate design within a class, as opposed to between classes. For instance, customer-driven costs, like natural gas meters, are not impacted by variations in gas usage or contribution to overall demand on a Design Day. Rather, such costs are affected by changes in the number of customers; the more customers the Company has, the more natural gas meters are needed.

Finally, the cost of serving each class is compared to the test year revenues generated by each class at current rates to determine the adjustment in revenues that is necessary for each class to recover its costs of service.

A guide to the Company's CCOSS is provided in Exhibit___(CJB-1), Schedule 2. The guide provides information on individual studies conducted for the purpose of developing allocators within the CCOSS study, descriptions of how calculations within the CCOSS are performed, and an index of external and internal allocators and their definitions.

B. External Allocators

Q. WHAT ARE EXTERNAL ALLOCATORS?

A. External allocators are calculated with data outside the CCOSS model (e.g., Design Day demands, metering, and customer service-related cost ratios). There are three types of external allocators: Capacity (Demand), Commodity (Energy), and Customer-related allocators.

Q. WHAT DISTRIBUTION PLANT STUDIES WERE CONDUCTED TO DEVELOP EXTERNAL ALLOCATORS WITHIN THE CCOSS?

A. The following is a list of studies that were conducted to develop the external allocators:

- Minimum System;
- Meter and Regulator Study;
- Service Study;

- Record & Collections Study;
- Customer Information Study;
- Uncollectibles Study; and
- Late Fee Study.

A full description of all seven studies is provided in Schedule 2. I describe minor refinements to the Minimum System Study in my testimony below.

Q. WHAT IS A MINIMUM SYSTEM STUDY?

A. A Minimum System Study identifies the portion of distribution plant associated with basic connectivity between the utility and the customer. The Minimum System Study determines the breakdown of costs that are customer-related (and therefore allocated with a customer-related allocator), versus those costs associated with capacity (and allocated with a demand-related allocator). As in the Company's last gas rate case, the Company conducted a Minimum-Sized Plant Study that identifies the smallest and most common distribution mains in a utility's system, identifies the cost per foot of the smallest and most common main, and applies that cost per foot to every main in the distribution system to derive the cost of a "minimum system." The cost of the minimum system is divided by the total costs of actual distribution mains in the system to derive the portion of distribution costs that are customer related. The remaining costs are split into average and excess capacity costs, which I discuss later in my testimony.

Q. WHAT METHODOLOGY ARE YOU PROPOSING FOR THE MINIMUM SYSTEM STUDY?

A. I am proposing a minimum-sized plant study using the same methodology that was used in the Company's last natural gas rate case (Docket No. G002/GR-21-678), with one modification – a demand adjustment to the Minimum System Study. The Minimum System Study is provided in Exhibit___(CJB-1), Schedule 4. However, as I described above, the Company is proposing to apply a demand adjustment to the Minimum System Study results.

Q. PLEASE DESCRIBE THE DEMAND ADJUSTMENT BEING APPLIED IN THE MINIMUM SYSTEM STUDY.

A. The Minimum System Study identifies distribution mains of two inches or less as its theoretical minimum system. The ratio of the cost of this minimum system compared to the total cost of distribution mains is used to determine the customer-related costs associated with distribution mains. However, distribution mains of two inches or less have some capacity. The Company is proposing to apply a demand adjustment that accounts for the carrying capacity of two-inch mains. Company engineers calculated the capacity of a two-inch pipe, and I utilized this capacity to calculate a demand adjustment in the Minimum System Study. Please see Exhibit___(CJB-1), Schedule 5 for the calculation of the demand adjustment.

Q. DID ANY OTHER STAKEHOLDERS RECOMMEND A DEMAND ADJUSTMENT IN THE LAST RATE CASE?

A. Yes. The Department of Commerce recommended a demand adjustment, and this proposal is responsive to their recommendation.

Q. WHAT OTHER KEY EXTERNAL ALLOCATORS ARE INCLUDED IN THE CCOSS?

A. The remaining external allocators are the Design Day Demand and Sales allocators. A full description of these is provided in Schedule 2.

C. Internal Allocators

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss internal allocators used in the CCOSS. Internal allocators are based on a combination of costs already allocated to the classes with external allocators.

Q. WHAT ARE THE PRIMARY INTERNAL ALLOCATORS?

A. The primary internal allocators include: 1) Average and Peak, 2) Mains, Overall, and 3) Production-Storage-Transmission-Distribution. A full description of these is provided in Schedule 2.

D. Changes and Improvements to CCOSS

Q. IS THE COMPANY'S CCOSS CONSISTENT WITH ITS PAST PRACTICE IN MINNESOTA?

A. Yes. The CCOSS conducted for this case is consistent with the CCOSS proposed by the Company in its last natural gas rate case (Docket No. G002/GR-21-678). Except for the new demand adjustment applied to the Minimum System Study, the allocation factors used in our previous gas rate case were used in this CCOSS. The various allocation percentages have been updated to reflect forecasted 2024 data on customers, sales, Design Day inputs, and other relevant items. The detailed CCOSS is included with Schedule 3 and Volume 3, Required Information, as part of the Company's rate case application.

IV. DECOUPLING OVERVIEW

Q. WHAT IS DECOUPLING?

A. Decoupling is a rate adjustment mechanism "designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency."[1] Typically, decoupling mechanisms accomplish this by means of an adjustment (either a credit or a surcharge) that trues up the revenues received by a utility to the authorized test year revenue requirement set by a commission in a rate case. In general, decoupling is used as a mechanism to better align the utility's interests with public policy goals (such as the promotion of energy efficiency), thus making it easier to achieve those goals. It can also ensure the utility is neither rewarded nor penalized for factors that affect energy consumption that are outside its control, such as unusual weather.

Q. WHAT PUBLIC POLICY SUPPORTS DECOUPLING?

A. When natural gas sales increase, so do potential revenues. This may create an incentive for a gas utility to maximize sales. By removing the link between energy sales and utility revenue, a decoupling mechanism can enable utilities to promote energy efficiency "systematically and aggressively"[2] without concern about the impact of reduced sales on their ability to recover fixed costs. As Minnesota's policy framework moves beyond simply energy efficiency and works specifically to reduce the use of geologically-sourced gas[3] – increasingly, through the activity of the gas utilities themselves – decoupling is an important

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[1] Minn. Stat. § 216B.2412, subd 1.
[2] Minn. Stat. § 216B.2401
[3] Minn. Stat. § 216B.2427, subd. 2(9)

tool that allows utilities to support such efforts with less concern about the impact on revenue. At the same time, by supporting the recovery of fixed costs, decoupling helps to ensure that critical energy infrastructure is available at times of peak need, even if overall throughput declines.

Q. WHAT IS THE STATUS OF THE COMPANY'S REVENUE DECOUPLING MECHANISM (RDM)?

A. In the Company's last rate case, the Commission approved a full revenue per customer RDM that includes the effect of weather in the calculation of decoupling deferrals with the following rules:

1. The RDM is implemented through final rates in the next natural gas rate case;
2. The RDM will include all customer classes with more than 50 customers;
3. The RDM has a 0.9 percent conservation requirement; and
4. The RDM will include customer charge revenue and distribution revenue in the RDM baseline and in the surcharge cap.

Q. PLEASE EXPLAIN THE COMPANY'S RDM PROPOSAL IN THIS RATE CASE.

A. The Company is proposing an extension of its current RDM rider, for RDM measurements to occur through the effective date of final rates in the next natural gas rate case. The RDM will continue measuring sales revenues against a baseline revenue-per-customer by class, with over- or under-recoveries credited or charged to customers through a dollar per therm factor applied to individual customer's monthly usage as a separate line item on their bill. For the proposed RDM tariff, see Gas Rate Book Sheet No. 71 included in Volume 2E of the rate case application. The Company's RDM model is attached as Exhibit___(CJB-1), Schedule 6.

The Company is proposing to include, in addition to the classes that are already decoupled, the Small Demand-Billed, Large Interruptible, Firm Transport, and Interruptible Transport customer classes. These classes have less than 50 customers each and are currently not included in our RDM. Customers on negotiated or flexible rates are not currently included in the RDM, and as discussed below, would continue to be excluded.

Q. HOW WILL THE RDM APPLY TO CUSTOMER CLASSES WITH LESS THAN 50 CUSTOMERS?

A. The Company is proposing to include the customer classes with less than 50 customers within the six RDM groups we have today, based on their similar rate design and type of service. For instance, our current RDM includes the Large Demand Billed class, but excludes the Small Commercial Demand Billed class. These classes have the same Distribution Charge with slight differences in their respective Customer Charges. Therefore, it is reasonable to combine these classes into one RDM group. The Medium and Large Interruptible classes take the same type of service with consistent rate structures, and can be appropriately grouped in the RDM. And, as discussed by Company witness Terwilliger, the Company's goal is to remain indifferent to customers' choice regarding gas supplier. Including the Transportation customers in RDM groups with their sales service counterparts would maintain the same rates for customers whether they are on sales service or transportation service. Table 3 lists the classes and groups that the Company is proposing to include in the RDM.

Table 3
Decoupled Classes

Group	Rate Code	Classes
Residential	101	Residential
Small Commercial	102, 108	Small Commercial
Large Commercial	118, 125	Large Commercial
Demand	103, 104, 119	Small Demand Billed Large Demand-Billed Firm Transport
Small Interruptible	105, 111, XXX	Small Interruptible
Medium/Large Interruptible	106, 107, 120, 123, 124, YYY, ZZZ	Medium Interruptible Large Interruptible Interruptible Transport

Q. WHY IS THE COMPANY PROPOSING TO OMIT SOME CUSTOMERS FROM THE RDM?

A. The Company is proposing to omit customers that are on negotiated or flexible rates. Minn. Stat. § 216B.163, subd. 4(1) states that flexible rates must at least recover the incremental cost to provide service. An RDM adjustment could cause a flexible rate to fall below incremental cost. Also, flexible rate customers have the capability to switch to alternate fuel supplies. Potential bill increases due to a decoupling surcharge could incent these customers to leave the system, leaving fewer sales over which to spread fixed costs. Therefore, we have excluded these customers from the RDM.

Q. THE COMPANY'S RDM CURRENTLY HAS A CAP ON SURCHARGES. IS THE COMPANY PROPOSING TO CONTINUE THIS CAP?

A. Yes. The Company is proposing to continue the cap currently in place, which is a maximum single-year class surcharge of 10 percent of the base revenue authorized for the class. This cap level on decoupling surcharges has previously been approved by the Commission for Xcel Energy[4], CenterPoint Energy (CenterPoint),[5] Minnesota Energy Resources Corporation (MERC),[6] and Great Plains Natural Gas.[7]

Q. UNDER THE PROPOSED RDM, CAN INDIVIDUAL CUSTOMERS BENEFIT FROM CONSERVATION?

A. Yes. If a customer reduces their usage in the near term, they will see immediate bill reductions for all volumetric charges including natural gas charges. Decoupling measures changes in revenues for the distribution component of the bill, and a decoupling surcharge would impact the distribution charge portion of the bill only. However, a customer who conserves would see savings on distribution charges, rider charges, and the largest component of their bill, natural gas charges. These savings would likely exceed a decoupling surcharge since it only impacts the distribution charge of the bill. An average residential customer who reduces their usage by five percent would likely see a bill reduction even while paying a decoupling surcharge at the proposed 10 percent surcharge cap.

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[4] *See In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G002/GR-21-678, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 6 (April 13, 2023).

[5] *See In the Matter of the Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 46-48 (June 9, 2014).

[6] *See In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G007,011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 13-14 (July 13, 2012).

[7] *See In the Matter of the Petition by Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G004/GR-15-879, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 40-43(Sept. 6, 2016).

Q. PLEASE SUMMARIZE THE RDM.
A. The proposed RDM will reduce the disincentive for pursuing increased energy conservation goals and achieving higher levels of gas savings. The RDM will also allow the Company to better align the utility's interests with public policy goals, thus making it easier to achieve those goals.

V. CONCLUSION

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.
A. The Company has prepared a fully-embedded CCOSS for this case, including background explanation on CCOSS concepts, as well as detailed documentation of the current CCOSS. This CCOSS meets all the objectives for proper CCOSS preparation, including identification of the revenues, costs, and profitability for each class of services, as required by Minn. R. 7825.4300, Subp. C. Other than some minor allocator updates, this version of the CCOSS adheres to the same methods employed by the Company in its previous rate cases. The results of this CCOSS have then been used by Company witness Terwilliger as the basis for rate design.

The Company has also proposed to continue the approved decoupling mechanism and include all customers not on flexible or negotiated rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?
A. Yes, it does.

Statement of Qualifications

Christopher J. Barthol

OVERVIEW

My responsibilities at Xcel Energy include Class Cost of Service Studies conducted in support of the Company's rate cases and providing pricing function support and other related analyses for the utility operating subsidiaries of Xcel Energy.

PROFESSIONAL EXPERIENCE

Rate Consultant; Xcel Energy, NSPM	2022 – Present
Principal Pricing Analyst; Xcel Energy, NSPM	2017 – 2022
Senior Regulatory Analyst; Xcel Energy, Xcel Energy Services	2015 – 2017
Pricing and Cost-of-Service Analyst; PacifiCorp	2013 – 2015
Associate Pricing and Cost-of-Service Analyst; PacifiCorp	2011 – 2013

EDUCATIONAL BACKGROUND

Purdue University; MS Agricultural Economics	2010
Saint Cloud State University; BA Economics	2008

Guide to the Gas Class Cost of Service Study (CCOSS)
Northern States Power Company

I. Overview

The purpose of the Northern States Power Company (NSP) gas Class Cost of Service (CCOSS) is to allocate ***joint*** (e.g.) and ***common*** costs to the designated "classes" of service such as residential, commercial, demand, interruptible, and transport. For example, distribution mains costs are "joint" between time periods and overhead costs such as management, are "common" to multiple functions, such as production, storage, transmission, and distribution. The CCOSS also assigns ***direct*** costs (e.g. purchased gas expenses), that may be associated with providing service to a particular customer from a specific class of service. The objective of the CCOSS is to make these cost ***allocations*** and ***assignments*** based on identifiable service requirements (e.g. Dth commodity usage and design day requirements), which are the drivers of the costs.

The two basic types of costs are: (1) capital costs associated with investment in production, storage, transmission, and distribution facilities and (2) on-going expenses such as purchased gas, labor costs and numerous other operating expenses. The end result is an allocation of the total utility costs (i.e. the revenue requirements) to customer classes according to each class's share of the capacity, commodity, and customer service requirements.

II. Major Steps of the Class Cost of Service Study

A CCOSS begins with a detailed documentation of the numerous budgetary elements of the total revenue requirement for the jurisdiction in question. The detailed jurisdictional revenue requirements are the data inputs to the CCOSS. At a high level, the CCOSS process consists of the following three basic steps:

1. <u>Functionalization</u> – The identification of each cost element as one of the six basic utility service "functions." The four main categories are production, storage, transmission, and distribution. There are also two other categories for general and common plant/expenses.
2. <u>Classification</u> – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g. Dths of demand, Dths of commodity usage or number of customers).
3. <u>Allocation</u> – The allocation of the functionalized and classified costs to customer classes, based on each class's respective service requirements (e.g. Dths of demand, Dths of commodity usage, and the number of customers, expressed in terms of a percentage of the total jurisdiction requirement).

III. Step 1: Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the gas utility system. Costs must first be functionalized because each class's service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The four main functions and the associated sub-functions are shown in the table below:

Function	FERC Accounts	Sub-Function	Description
Production	304, 305, 311, 108(1), 190, 281-283 Net, 710, 733, 735, 736, 742, 759, 840-843, 403, 408.1, 410.1, 411.1, 420	None	Includes capital and associated operations and maintenance expenses related to manufacturing, buying, or producing gas. These costs include pipeline or producer gas purchases and producing owned or peaking gas.
Storage	360-363, 108(5), 190, 281-283 Net, 403, 408, 410.1, 411.1, 420	None	Includes capital and associated operations and maintenance expenses related to storing off-peak gas for use during the winter-peaking months.
Transmission	365-371, 108(7), 190, 281-283 Net, 107, 850-865, 403, 408.1, 410.1, 411.1, 420	None	Includes costs associated with transporting gas from interstate pipelines to the Company's distribution system. These included capital costs associated with transmission mains as well as operations and maintenance expenses associated with town border stations.
Distribution	374-376, 378-381, 383, 108(8), 281-283 Net, 107, 871, 874, 875, 877-881, 885, 887, 889, 891, 892, 403, 408, 410.1, 411.1, 420	"Customer" portion of the Distribution Mains	Includes the customer-related capital and operating costs associated with delivering gas to customers (distribution mains and services, customer services, meters, regulators)
		"Demand" portion of Distribution Mains	Includes the demand-related capital and operating costs associated with delivering gas to customers (distribution mains and services, customer services, meters, regulators)

IV. Step 2: Cost Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs. The three principal service requirements or billing components are:

1. Demand – Costs that are driven by customers' maximum dekatherm ("Dth") demand.
2. Commodity – Costs that are driven by customers' energy or dekatherm ("Dth") requirements.

3. Customer – Costs that are related to the number of customers served.

The table below shows how each of the functional and sub-functional costs were classified:

Function/Sub-Function	**Cost Classification**		
	Demand	**Customer**	**Commodity**
Production	X		X
Storage	X		
Transmission	X		
Distribution (Customer-Related)		X	
Distribution (Demand-Related)	X		

As shown in the table above, distribution costs are classified as both "demand" and "customer" related. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system. The Company utilizes a minimum system methodology for determining the portion of costs that are demand- and customer related.

V. Step 3: Cost Allocation to Customer Class (Assignment of Costs to Customer Classes)

The third step in the CCOSS process is allocation, which is the process of assigning (allocating or directly assigning) functionalized and classified costs to customer classes. Generally, cost assignment occurs in one of two ways:

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. An example of a directly assigned cost is purchased gas expenses or transmission mains.
- Allocation - Most gas utility costs are incurred common or jointly in providing service to all or most customers and classes. Therefore, allocation methods must be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.
  - Class allocators (sometimes called allocation strings) are simply a "string" of class percentages that sum to 100 percent.
  - There are two types of allocators:
    - External Allocators –These are allocators that are based on data from outside the CCOSS model (e.g. design day demands, metering and customer service-related cost ratios). In general, there are three types of external allocators:
      - Capacity –related (sometimes referred to as Demand) allocators such as:
        - Design Day Demands – each firm class's usage in extreme peaking conditions
        - Excess Design Day – the portion of design day demand in excess of average daily sales
      - Commodity-related allocators such as:
        - Sales W/Transp – Forecasted sales, including forecasted transportation sales

    - Sales W/o Transp – Forecasted sales without forecasted transportation sales
  - Customer-related allocators
    - Number of customers
    - Weighted number of customers, where the weights are based on cost of meters, services, billing, etc.

  Details on the external allocators used in the CCOSS model are shown in Volume 3, Required Information, Page 10.

- Internal Allocators – These are allocators based on combinations of costs already allocated to the classes using external allocators. These internal allocators are used to assign certain costs, which are most appropriately associated with and assigned to classes by some combination of other primary service requirements, such as Dths demand, Dths of energy or the number of customers. Examples of internal allocators include:
  - Average and Peak – portion of mains costs that are not allocated on customers
  - Mains, Overall – total effect of mains allocated on customers, sales with transport, and excess design day
  - Prod-Stor-Trans-Distr – Total production, storage, transmission, and distribution from original plant investment

  Details on the development of the internal allocators used in the CCOSS model are shown in Volume 3, Required Information, Page 9.

VI. Classification and Allocation of Production, Storage, Transmission, and Distribution Plant and Expenses

A. Production and Storage Plant

Production costs include production-related land and land rights, structures and improvements, liquefied petroleum, and other expenses. Storage costs also include storage-related land and land rights, structures and improvements, gas holders, and purification equipment. These costs are classified as demand-related and allocated with a Design Day allocator. Production-related expenses such as the Minnesota Manufactured Gas Plant (MGP) are classified as energy-related and allocated with a Sales Without Transport allocator.

B. Transmission Plant

Transmission costs include transmission pipe-related land and land rights, rights-of-way used in connection with transmission operations, structures and improvements, and transmission mains. Transmission main costs that can be segregated to a specific class are directly assigned to that class. Those costs that are not directly assigned are classified as demand-related and allocated with an average and peak allocator.

C. Distribution Plant

Distribution Plant includes the pipelines, meters, and other infrastructure needed to deliver natural gas from the transmission system to customers' premises. The categories of Distribution Plant are: 1) distribution mains, 2) services (i.e., the pipe going to homes and businesses), 3) meters and regulators, and 4) regulator stations. The Table below shows the amount of distribution plant by category and how they are classified:

Distribution Plant Category	2022 TY Plant in Service (000)	Demand Component	Customer Component
Distribution Mains	$1,045,593	X	X
Services	$386,499		X
Meters & Regulators	$147,691		X
Regulator Stations	$31,250	X	

VII. Distribution Plant Cost Studies within CCOSS

There are three distribution cost studies within the CCOSS:

- Minimum System Study
- Meter and Regulator Study
- Service Study

<u>Minimum System Study</u>
The National Association of Regulatory Utilities Commissioners (NARUC) Gas Distribution Rate Design manual states that a portion of distribution mains may be classified as customer-related (with the remainder of costs classified as demand related) and that Minimum System studies may be utilized to derive the customer- and demand-related components of distribution mains. Consistent with this guidance, I utilized a Minimum System Study to establish the classification percentages of distribution mains.

The Minimum System method involves comparing the cost of the minimum size of distribution mains used, to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the minimum sized cost. The table below shows the classification of distribution main costs.

Cost	Customer	Demand
Distribution Costs	**61.0%**	**39.0%**

The total cost of mains is split among Minimum System, Average Capacity, and Excess Capacity components. The Minimum System component identifies the cost to establish basic connectivity between the utility and the customer, using pipes with a diameter of two inches or less, which is the minimum-sized pipe for mains on our system. If all the mains in the Company's entire distribution system in Minnesota consisted of two-inch pipe, the initial plant investment would have been 61.0 percent of actual investment. These Minimum System costs are allocated to class based on the number of customers in each class and are also assigned to the Customer Charge billing component. However, it is reasonable to make a demand adjustment that accounts for capacity associated with the two-inch pipe that makes up the Minimum System. The Company calculated a demand adjustment of 20.3 percent. The following table illustrates the adjusted customer- and demand-related classification of distribution main costs.

Cost	Customer	Demand
Distribution Costs	**40.6%**	**59.4%**

Average Capacity costs are determined by taking the remaining 59.4 percent of the total cost of mains and multiplying by the test year 2024 system load factor. The system load factor is calculated by taking the Company's forecasted total sales (2024 Test Year Sales forecast of 118,778,662 Dth) and dividing that by the Company's peak demand (2023-2024 Design Day Demand of 898,926 Dth) and multiplying that by 365 days in the year. The test year 2024 forecasted system load factor is 36.2 percent. Multiplying the 59.4 percent of the remaining total cost of mains by the system load factor leads to an Average Capacity of 21.5 percent. These Average Capacity costs are allocated to class based on sales (including transportation sales). Then the results are credited to the Demand billing component and Base sub-component. The Base sub-component is comprised of non-seasonal and non-peak demand.

The Excess Capacity component is the remaining 37.9 percent of total cost of mains not ascribed to the Minimum System and Average Capacity components. The Excess Capacity costs are allocated to class using an Excess Design Day allocator. The Excess Design Day allocator is calculated by taking the difference between each class's Design Day demand and Average Daily Sales. Then, each class amount is credited to the Demand cost component and Seasonal sub-component.

Meter and Regulatory Study

A Meter and Regulator Study assigns meter costs and costs for pressure-regulating equipment to each class. Information is gathered on meter and regulator equipment and installation costs, the premises identification numbers associated with different meters, and the premises identification numbers associated with each rate code/class. From this list, total meter costs are developed for each class and divided by the number of meters in each class to develop a cost per meter weighting. Since the residential class had the lowest cost per meter and regulator, they received a customer weighting of 1.00. The weightings for each class are as follows: Residential – 1.00, Small Commercial – 1.75, Large Commercial – 5.17, Small Demand – 12.53, Large Demand – 22.88, Small Interruptible – 15.63, Medium Interruptible – 36.26, Large Interruptible – 22.76, Firm Transport – 22.88, Interruptible Transport – 36.26, Negotiated Transport – 22.76, System Generation – 19.08, and Transport Generation – 22.85. The meter cost weighting for each class is applied to the number of customers in each respective class in order to calculate the Meters and Regulators Study allocator.

Service Study

A Services Study assigns gas services costs to each class. Services costs are the costs of service pipelines used to connect distribution mains to customers' premises. Information is gathered on premise identification numbers, service pipe type, service pipe length, and class associated with each premise. The cost per foot of each service pipe type is applied to each class based on the service pipe types and footage used in each class. This calculation allows us to determine the total cost of service pipes for each class. The total cost by class is divided by the number of customers in each class. Since the cost per customer for the residential class was lowest, that class received a weight of 1.00. The weightings for each class are as follows: Residential – 1.00, Small Commercial – 1.71, Large Commercial – 2.12, Small Demand – 4.27, Large Demand – 5.05, Small Interruptible – 9.53, Medium Interruptible – 5.91, Large Interruptible – 6.89, Firm Transport – 5.05, Interruptible Transport – 5.91, Negotiated Transport – 6.89, System Generation – 5.48, and Transport Generation – 5.97. The service weightings are applied to the number of customers in each class. The weighted customers are then utilized to derive the Service Study allocator.

VIII. Other Cost Studies within CCOSS

Customer Care Studies

Two Customer Care studies were conducted within the CCOSS: 1) a Customer Records and Collections Study and 2) a Customer Information Study. The Customer Records and Collections Study, and the Customer Information Study were developed to allocate costs associated with Federal Energy Regulatory Commission (FERC) Accounts 903 and 908, respectively. FERC Account 903 costs include materials used and expenses incurred in work on customer applications, contracts, orders, credit investigations, billing and accounting, collections, and complaints. FERC Account 908 costs include materials used, and expenses incurred in providing instructions or assistance to customers, the object of which is to promote safe, efficient, and economical use of the utility's service.

The Customer Records and Collections Study first determines the costs associated with billing and call centers for each class on a cost per customer basis. To make this determination, I first directly assign those FERC Account 903 costs that can be directly assigned to a specific class. Those FERC Account 903 costs that cannot be directly assigned are allocated based on the number of customers in each class. The weightings for each class are as follows: Residential – 1.00, Small Commercial – 0.95, Large Commercial – 0.84, Small Demand – 60.00, Large Demand – 60.00, Small Interruptible – 60.00, Medium Interruptible – 60.00, Large Interruptible – 60.00, Firm Transport – 60.00, Interruptible Transport – 60.00, Negotiated Transport – 60.00, System Generation – 60.00, and Transport Generation – 60.00. The weightings are derived for all other classes by dividing their cost per customer by that of the residential class. The weightings are then applied to the number of customers in each class. The weighted customers are used to derive the allocator for customer records and collections expenses.

In the same manner as the Customer Records and Collections Study, the Customer Information Study determines the costs associated with customer account management, expenses associated with low-income customers, and business development by directly assigning the FERC Account 908 costs that can be directly assigned to a specific class. Costs that cannot be directly assigned to a class are allocated based on the number of customers in each class.

The weightings for each class are as follows: Residential – 1.00, Small Commercial – 0.93, Large Commercial – 10.00, Small Demand – 60.00, Large Demand – 60.00, Small Interruptible – 60.00, Medium Interruptible – 60.00, Large Interruptible – 30.00, Firm Transport – 60.00, Interruptible Transport – 60.00, Negotiated Transport – 30.00, System Generation – 60.00, and Transport Generation – 60.00. The weightings are derived for all other classes by dividing their cost per customer by that of the residential class. The weightings are then applied to the number of customers in each class. The weighted customers are used to derive the allocator for costs associated with customer account management, expenses associated with low-income customers, and business development.

Uncollectibles Study
The Uncollectibles Study consists of gathering information on customer debtor numbers, net uncollectibles (bad debt less recoveries) for each debtor number, and classes associated with each debtor number to determine the net uncollectibles for each class. The net uncollectibles are then calculated for each class and used to derive the allocation of uncollectibles.

Late Fee Study
The Late Payment Study follows the same process as the Uncollectibles Study as it determines customer late fees by class. The late fees by class are used to derive the late fee revenue allocator and assign late payment revenues to each customer class.

IX. Direct Assignment of Transmission Plant and Related Expenses

Plant and related expenses associated with transmission mains that only serve two of our Transport Generation customers were isolated and directly assigned to that class. Production, storage, and distribution plant and related expenses related to these two customers were not allocated to the Transport Generation class by removing their respective sales from the Modified Sales W/Transport allocator, customer counts from the Modified Customer Counts allocator, and Design Day demands from the Design Day and Excess Design Day allocators. For transmission plant and related expenses, the remaining costs that are not directly assigned are allocated to the classes via the average and peak allocator.

X. Customer Class Definitions

Ideally, there would be no customer class groupings and cost allocation would reflect the unique costs of each individual customer. Because this is not possible, it is necessary to develop a cost study process that identifies costs of service for groups of customers ("classes") where the customers of the class have similar cost/service characteristics. The basic classes of service employed in the Company's CCOSS are the following:

1. Residential
2. Small Commercial
3. Large Commercial
4. Small Demand
5. Large Demand
6. Small Interruptible
7. Medium Interruptible
8. Large Interruptible
9. Firm Transport
10. Interruptible Transport
11. Negotiated Transport
12. System Generation
13. Transport Generation

XI. Organization of the CCOSS Model

The CCOSS model consists of numerous worksheets which show costs by customer class in Total (as shown on the worksheet tab labeled "Tot") and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below (the label of the worksheet tab is shown in parenthesis below):

1. Billing Unit:
    a. Demand (Dem)
    b. Customer (Cus)
    c. Commodity (Com)

2. Function and Associated Sub-Function
    a. Demand (Dem)
        a) Base (Base)
        b) Seasonal (Seas)
        c) Peak Shaving (Peak)

In the CCOSS spreadsheet there is a separate worksheet tab for each of the above billing units, functions and sub-functions. This multi-level breakdown of costs is useful for designing rates as well as for determining class revenue responsibilities.

XII. CCOSS Calculations

Listed below are important calculations that are part of the CCOSS model. These calculations occur at the "TOT" layer of the CCOSS as well as each of the "sub-layers" for each billing component, function and sub-function. Showing results at the more detailed billing component, function and sub-function levels is important for rate design purposes.

A. Rate Base Calculation

Rate Base = Original Plant in Service – Accumulated Depreciation Reserve – Accumulated Deferred Income Tax + Additions to Net Plant

The above rate base calculation occurs on "TOT" layer as well as each function/sub-function layer.

B. Revenue Requirements Calculation (Class Cost Responsibility)

The Revenue Requirements Calculation (sometimes referred to as the "Backwards Revenue Requirement Calculation) is used to calculate "cost" responsibility for each customer class. This has to be done within the CCOSS model because the JCOSS model does it only at the total jurisdiction level, not by class. The class "cost" responsibility is based on the same return on rate base for each class that is equal to the overall proposed rate of return. In other words, class revenues requirements are calculated to provide the same return on rate base for each customer class. This calculation occurs on the "TOT" layer as well as for each function, sub-function, and billing component after all expenses and rate base items have been allocated. As such, class cost responsibility is available for each function, sub-function, and billing component. This analysis serves a starting point for rate design. The formula is shown below:

Retail Revenue Requirement = Expenses (less off-setting credits from Other Operating Revenues)

+

(((% Return on Invest x Rate Base) - AFUDC - Fed Credits) x 1 / (1 - Fed T) - Fed Section 199 Deduc x Fed T/(1-Fed T) - State Credits) x 1 / (1 - State T)

+

(Tax Additions – Tax Deductions) x Tax Rate / (1-Tax Rate)

Where:

Tax Rate = 1 – (1- State T) x (1-Fed T)

Expenses = O&M + Book Depreciation + Real Estate & Property Tax + Payroll Tax
+ Net Investment Tax Credit – Other Retail Revenue – Other Oper. Revenue

Tax Additions = Book Depreciation + Deferred Inc Tax + Net Inv Tax Credit
+ Other Misc Expenses.

Tax Deductions = Tax Depreciation + Interest Expense + Other Tax Timing Diff

C. Total Return and Return on Rate Base (Based on Class Revenue Responsibility)

After rates have been designed and each class's "revenue" responsibility has been determined, the model calculates total return and return on rate base using the following formulas. These calculations are performed at both present and proposed rate levels.

Total $ Return = Revenue – O&M Expenses – Book Depr.
– Real Estate & Property Taxes – Provision for Deferred Inc Taxes – Inv. Tax Credits
– State & Federal Income Taxes + AFUDC

Percent Return on Rate Base = Total $ Return / $ Rate Base

After rates have been designed, the return on rate base is typically different for each customer class. In other words, the resulting class "revenue" responsibility differs from class **"cost"** responsibility.

XIII. Allocator Descriptions

In the table below, the Name column briefly describes what the allocator is, and the Derivation column describes how the allocator was created. The E/I column tells whether an allocator is external or internal. (An external allocator is one that was prepared outside of the CCOSS. An internal allocator is created within the CCOSS by combining the results of external allocators and / or other internal allocators.) The Components column indicates to which billing component(s) the allocator applies, including possibly the two demand subcomponents. (C=Customer, D=Demand, E=Energy, B=Base Demand, S=Seasonal Demand and P=Peak Shaving Demand). Most lines of this table show normal allocators that first spread dollars to class and then spread each class amount to billing and subcomponents. But some allocators, such as Present Retail Revenue, only spread dollars to class. And a few other allocators, such as

Mod Present Revenue, only spread dollars to billing component. (These latter allocators are only used after dollars have already been spread to class-by-class allocators.) Such two-stage allocations are indicated in the Alloc column of the CCOSS with a semi-colon (e.g., "Pres Rev; Mod Pres Rev").

Name	Derivation	E/I	Components
1/2 Dsgn Day, 1/2 Ener	Average class percents from the Design Day and Sales, W/ Transp allocators	Int	DE- P
1/2 Mod Rt Bs, 1/2 Mod Pres Rv (Component only)	Average class percents from Mod Pres Rev and Mod Rate Base column allocators	Int	CDE-BSP
1/2 Rt Base, 1/2 Pres Rev; (Class only)	Average class percents from the Rate Base and Present Retail Revenue allocators	Int	---
Average and Peak	Total effect of mains allocated on excess design day and average sales	Int	D -BS
Cust Inform Study	Forecasted customers, weighted by the typical cost to serve each class	Ext	C -
Customers	Forecasted customers	Ext	C -
CWIP	Construction Work In Process	Int	CD -BSP
Design Day	Each firm class's participation in extreme peak conditions	Ext	D - P
Dist Exp, w/o Sup & Eng	Distribution O&M expenses, excluding Supervision & Engineering	Int	CDE-BSP
Distribution Plant	Total original investment in mains, services, meters and regulators	Int	CD -BS
Excess Design Day	The portion of Design Day in excess of average daily sales	Ext	D - P
Gas Plant In Service	Total original capital investments	Int	CD-BSP
Labor	Total of various labor-related expenses	Int	CDE-BSP
Labor w/o A&G	All labor expenses except A&G	Int	CDE-BSP
Late Pay Penalties (Class only)	Late pay penalties	Ext	---
Mains, Overall	Total effect of mains allocated on customers, sales with transport & excess design day	Int	CD -BS
Meter & Regul Study	Customer count, weighted by relative cost of each class's average meter and regulator	Ext	C -
Mod Present Reven (Component only)	Present Retail Revenue, w/o Gross Earnings, Late Pay, etc.	Int	CDE-BSP
Mod Rate Base (Component only)	Column version of Rate Base excluding Working Cash	Int	CDE-BSP
Modified O&M Expense	Total O&M expense, less rate case expense and various Admin & General expenses	Int	CDE-BSP
Net Plant	Plant In Service, minus Accumulated Depreciation	Int	CD -BSP
Other Production Expense	Miscellaneous production expenses for LPG, LNG, etc.	Int	DE- P
Present Retail Rev (Class only)	Forecasted present revenue	Ext	---
Prod-Stor-Tran-Dis	Total Production, Storage, Transmission and Distribution, from original plant investment	Int	CD -BSP
Rate Base	Rate Base (Plant in Svc, less Accumulated Deprec, plus and minus other adjustments)	Int	CDE-BSP
Record & Coll Study	Forecasted customers, weighted by typical cost to provide billing records and collections	Ext	C -
Rt Base, w/o Work Cash	Rate base, excluding working cash	Int	CDE-BSP
Sales, W/ Transp	Forecasted sales, including forecasted transportation	Ext	E-

Name	Derivation	E/I	Components
Sales, W/o CIP Exempt	Forecasted sales, w/o forecasted CIP-exempt sales	Ext	E-
Sales, W/o Transp	Forecasted sales, w/o forecasted transportation	Ext	E-
Service Study	Customer count, weighted by relative cost of each class's average service	Ext	C -
Tran & Distrib	Transmission and Distribution plant (original investment)	Int	CD -BS
Uncollectibles Study	Forecasted customers, weighted by the typical cost of each class's uncollectibles	Ext	C -

XIV. Allocator Index

The following table lists all the CCOSS allocators, in alphabetical order. If a given allocator is used multiple times within the CCOSS, those occurrences are further sorted by page and line number. Most allocators are used to spread dollars both to class and then billing component. But as indicated parenthetically, some allocators are used only for class allocations or only for billing component allocations.

Allocator	Category	Item	Page	Line
1/2 Dsgn Day, 1/2 Ener	Pres Other Oper Rev	Other - Miscellaneous	5	11
	Other Production Exp	Misc. LNG Op Exp	5	26
	Distribution O&M Exp	Dispatching	5	37
1/2 Rt Base, 1/2 Pres Rev (Class only)	Admin & General	Injuries and Claims	6	15
		General Advertising	6	18
		Misc General Exp	6	19
		Rents	6	20
		Maint of Gen Plt	6	21
Average and Peak	Plant in Service	Transmission Plant	3	3
		Regulator Stations	3	6
	Accum Depr Rsv	Transmission Plant	3	20
		Regulator Stations	3	23
	Accum Defer IT	Transmission Plant	3	35
		Regulator Stations	3	38
	CWIP	Transmission Plant	4	3
		Regulator Stations	4	6
	Transmiss O&M Exp	Transmission Expense	5	28
	Distribution O&M Exp	Regulator Stations	5	31
	Book Deprec	Transmission Plant	6	32
		Regulator Stations	6	35
	Rl Estate & Prop Tax	Transmission Plant	7	3
		Regulator Stations	7	6
	Provis-Defer Inc Tax	Transmission Plant	7	19
		Regulator Stations	7	22

Allocator	Category	Item	Page	Line
Average and Peak	Investment Tax Credit	Transmission Plant	7	35
		Regulator Stations	7	38
	Tax Depr & Removal	Transmission Plant	8	3
		Regulator Stations	8	6
	AFUDC	Transmission Plant	8	36
		Regulator Stations	8	39
Cust Inform Study	Cust Acctg & Inform	Asst Expense (w/o CIP)	6	6
Customers (Also Modified Customers)	Plant in Service	Mains - Minimum System	3	7
	Pres Other Oper Rev	Connection Charges	5	4
		Return Check Charges	5	5
		Connect Smart	5	6
		Distribution Other	5	10
		Incr Misc Serv	5	14
	Distribution O&M Exp	Other Property & Equipment	5	36
		Customer Installations	5	38
		Other Distribution	5	39
	Cust Acctg & Inform	Acct Superv	6	1
		Acct Meter Read	6	2
		Acct Misc	6	5
	Labor Allocator	Customer Accounting	8	48
		Cust Serv & Inform	8	49
CWIP	Income Tax Additions	Avoided Tax Interest	8	19
	AFUDC	Total AFUDC	8	29

Allocator	Category	Item	Page	Line
Design Day	Plant in Service	Production Plant (LPG)	3	1
		Storage Plant (LNG)	3	2
	Accum Depr Rsv	Production Plant (LPG)	3	18
		Storage Plant (LNG)	3	19
	Accum Defer IT	Production Plant (LPG)	3	33
		Storage Plant (LNG)	3	34
	CWIP	Production Plant (LPG)	4	1
		Storage Plant (LNG)	4	2
	Pres Other Oper Rev	Interchange Gas	5	7
		Damage Claim	5	8
		Ltd Firm Sales - Rsrvs & Vols	5	9
	Purchased Gas Exp	Propane	5	20
		Limited Firm	5	21
	Other Production Exp	Other Purchased Gas	5	23
		Misc. LPG Op Exp	5	25
	Book Deprec	Production Plant (LPG)	6	30
		Storage Plant (LNG)	6	31
	Rl Estate & Prop Tax	Production Plant (LPG)	7	1
		Storage Plant (LNG)	7	2
	Provis-Defer Inc Tax	Production Plant (LPG)	7	17
		Storage Plant (LNG)	7	18
	Investment Tax Credit	Production Plant (LPG)	7	33
		Storage Plant (LNG)	7	34
	Tax Depr & Removal	Production Plant (LPG)	8	1
		Storage Plant (LNG)	8	2
	AFUDC	Production Plant (LPG)	8	34
		Storage Plant (LNG)	8	35
	Labor Allocator	Transmission	8	54
	Plant in Service	Transmission	3	4
	Accum Depr Rsv	Transmission	3	21
	Accum Defer IT	Transmission	3	36
	CWIP	Transmission	4	4

Allocator	Category	Item	Page	Line
Design Day	Purchased Gas Exp	Commodity	5	18
		Demand	5	19
	Book Deprec	Transmission	6	33
	Real Estate & Prop Taxes	Transmission	7	4
	Provis-Defer Inc Tax	Transmission	7	20
	Investment Tax Credit	Transmission	7	36
	Tax Depr & Removal	Transmission	8	4
	AFUDC	Transmission	8	37
Direct Assign (Class only)	Pres Retail Revenue	Present Retail Rev	5	1a
	Prop Retail Revenue	Proposed Retail Rev	5	1b
Dist Exp, w/o Sup & Eng	Distribution O&M Exp	Supervision & Engineering	5	40
	Labor Allocator	Distribution	8	50
Excess Design Day	Plant in Service	Mains - Excess Capacity	3	9
Labor	Accum Defer IT	Non-Plant Related	3	47
	Non-Plt Asset-Liab	Non-Plant Assets & Liab	4	15
	Admin & General	Pension & Benefit-Direct	6	9
		Salaries	6	10
		Office & Supplies	6	11
		Admin Transfer Credit	6	12
		Outside Services	6	13
		Incentive Compensation	6	14
	Cust Service & Info	Amortizations	6	24
	Tot Rl Est & Prop Tax	Payroll Taxes	7	15
	Provis-Defer Inc Tax	Non-Plant Related	7	31
	Inc Tax Deductions	Other Timing Differences	8	23
		Meals	8	24
Labor w/o A&G	Labor Allocator	Admin & General	8	51
Late Payment Study	Pres Other Oper Rev	Late Pay Penalties	5	3
	Prop Other Oper Rev	Incr Late Pay - Proposed	5	13

Allocator	Category	Item	Page	Line
Mains, Overall	Accum Depr Rsv	Mains	3	24
	Accum Defer IT		3	39
	CWIP		4	7
	Distribution O&M Exp		5	32
	Book Deprec		6	36
	Rl Estate & Prop Tax		7	7
	Provis-Defer Inc Tax		7	23
	Investment Tax Credit		7	39
	Tax Depr & Removal		8	7
Meter & Regul Study	Plant in Service	Meters	3	12
		House Regulators	3	13
	Accum Depr Rsv	Meters	3	26
		House Regulators	3	27
	Accum Defer IT	Meters	3	41
		House Regulators	3	42
	CWIP	Meters	4	9
		House Regulators	4	10
	Distribution O&M Exp	Meters	5	34
		House Regulators	5	35
	Book Deprec	Meters	6	38
		House Regulators	6	39
	Rl Estate & Prop Tax	Meters	7	9
		House Regulators	7	10
	Provis-Defer Inc Tax	Meters	7	25
		House Regulators	7	26
	Investment Tax Credit	Meters	7	41
		House Regulators	7	42
	Tax Depr & Removal	Meters	8	9
		House Regulators	8	10
	AFUDC	Meters	8	42
		House Regulators	8	43
Modified O&M Expense	Working Cash	Total Working Cash	4	20

Allocator	Category	Item	Page	Line
Net Plant	Accum Defer IT	Accumulated Deferred Tax	3	46
	Admin & General	Property Insurance	6	8
	Provis-Defer Inc Tax	Tax Benefit Transfers	7	30
	Tax Depr & Removal	Tax Benefit Transfers	8	14
Other Production Exp	Labor Allocator	Production	8	52
Present Rev; Mod Pres Rev (Class only)	Admin & General	Regulatory Comm Exp	6	16
		Duplicate Charge Credit	6	17
	Amortizations	Rate Case Exp Amort	6	25
Prod-Stor-Tran-Dis	Plant in Service	General Plant	3	15
		Common Plant	3	16
	Accum Depr Rsv	General Plant	3	29
		Common Plant	3	30
	Accum Defer IT	General Plant	3	44
		Common Plant	3	45
	CWIP	General & Common Plant	4	11
	Book Deprec	General Plant	6	41
		Common Plant	6	42
	Rl Estate & Prop Tax	General Plant	7	12
		Common Plant	7	13
	Provis-Defer Inc Tax	General Plant	7	28
		Common Plant	7	29
	Investment Tax Credit	General Plant	7	44
		Common Plant	7	45
	Tax Depr & Removal	General Plant	8	12
		Common Plant	8	13
	AFUDC	General Plant	8	42
		Common Plant	8	43
Record & Coll Study	Cust Acctg & Inform	Acct Recrds & Coll	6	3
Sales, W/ Transp & Modified Sales W/Transp	Plant in Service	Mains - Average Capacity	3	8
	Gas In Storage	Total Gas in Storage	4	14
	Sales Expense	Sales, Econ Dvlp & Other	6	27
	Labor Allocator	Sales	8	53

Allocator	Category	Item	Page	Line
Sales, W/o CIP Exempt	Amortizations	CIP / DSM Amortization	6	23
Sales, W/o Transp	Miscellaneous	Fuel	4	18
	Other Prod Expense	MGP	5	24
Service Study	Plant in Service	Services	3	11
	Accum Depr Rsv		3	25
	Accum Defer IT		3	40
	CWIP		4	9
	Distribution O&M Exp		5	33
	Book Deprec		6	37
	Rl Estate & Prop Tax		7	8
	Provis-Defer Inc Tax		7	24
	Investment Tax Credit		7	40
	Tax Depr & Removal		8	8
	AFUDC		8	41
Tran & Distrib	Material & Supply	Materials & Supplies	4	13
	Miscellaneous	Prepay: Insurance	4	16
		Prepay: Miscellaneous	4	17
Uncollectibles Study	Cust Acctg & Inform	Acct Uncollect	6	4

XV. Class Cost of Service Table of Contents

Page 1 contains a summary of the allocated rate base and income statement.

Page 2 contains the revenue deficiency/excess by class assuming each class has an equal return on rate base. It also shows the classification components (e,g., customer related, capacity related). This can be used to design cost-based intra-class rates for customers. For example, the CCOSS shows the total revenue deficiency for the residential customer class as $45,538,289 and the cost-based customer charge for residential of $23.48 per month. The cost classifications (e.g.

customer related) are only shown as a total class revenue deficiency. However, the Company does have the same data as below for each cost classification category.

Pages 3 through 8 contain in more detail the components of the rate base and income statement along with the method used to allocate the various cost components. Each item contains a line number along with a description of the item. For those items that use an allocator to split the costs between classes, the next column ("Alloc") shows the name of the allocation method. A value that is not allocated but directly assigned to each class will contain the designation "Direct." Calculated lines such as subtotals do not have a designation in this column. The remaining columns contain the Minnesota jurisdictional total and the class cost allocations for each item.

Pages 9 and 10 contain external allocators and certain internal allocation percentages.

Page 11 contains certain cost of capital items and tax rates used in the CCOSS.

Class Cost of Service Study ($000); Test Year 2024

SUMMARY

Rate Base		Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Production	75,274	39,991	22,852	2,416	0	485	9,529
2	Storage	94,123	50,006	28,574	3,021	0	606	11,916
3	Transmission	134,424	55,594	31,860	3,412	3,126	4,998	35,433
4	Distribution	1,611,639	1,176,990	288,233	20,420	20,478	27,833	77,685
5	General	272,283	188,005	52,812	4,161	3,355	4,822	19,128
6	Common	0	0	0	0	0	0	0
7	**Total Plant In Service**	**2,187,742**	**1,510,586**	**424,332**	**33,430**	**26,959**	**38,745**	**153,691**
8	Production	19,856	10,549	6,028	637	0	128	2,514
9	Storage	45,901	24,386	13,935	1,473	0	296	5,811
10	Transmission	32,868	13,358	7,656	820	751	1,201	9,082
11	Distribution	565,353	432,235	95,142	5,518	5,968	7,051	19,439
12	General	121,351	83,790	23,537	1,854	1,495	2,149	8,525
13	Common	0	0	0	0	0	0	0
14	**Total Depreciation Reserve**	**785,328**	**564,318**	**146,298**	**10,302**	**8,214**	**10,824**	**45,370**
15	**Net Plant**	**1,402,415**	**946,267**	**278,034**	**23,128**	**18,745**	**27,921**	**108,320**
16	**Deductions** (Accum Def Inc Tax)	**214,540**	**152,415**	**38,779**	**2,733**	**2,673**	**3,561**	**14,379**
17	**Additions**	**79,988**	**38,140**	**16,403**	**1,753**	**2,638**	**5,148**	**15,906**
18	**Rate Base**	**1,267,863**	**831,992**	**255,658**	**22,148**	**18,710**	**29,507**	**109,847**

Income Statement		Minn	Res	Com	Demand	Interrupt	Tran	Gener
19	**Present Retail Revenue**	**617,806**	**364,900**	**179,310**	**19,847**	**37,592**	**7,374**	**8,783**
20	**Present Other Oper Rev**	**4,230**	**2,940**	**744**	**71**	**45**	**70**	**361**
21	**Present Total Operating Rev**	**622,037**	**367,840**	**180,055**	**19,918**	**37,636**	**7,444**	**9,144**
	Operating & Maint Expenses							
22	Purchased Gas Expense	350,434	193,344	114,738	13,382	28,111	0	860
23	Other Purch Gas Exp	0	0	0	0	0	0	0
24	Other Production	7,927	3,990	2,303	254	186	154	1,041
25	Transmission	623	306	175	19	17	28	78
26	Distribution	39,553	29,567	6,057	471	464	739	2,255
27	Customer Accounting	12,887	11,437	1,147	107	171	19	7
28	Customer Service and Information	910	669	204	13	21	2	1
29	Administrative and General	27,550	19,131	5,351	485	599	456	1,527
30	Amortizations; Sales Expense	29,786	15,362	8,890	1,098	2,949	1,343	145
31	**Total Operating & Maint Exp**	**469,670**	**273,807**	**138,865**	**15,829**	**32,517**	**2,741**	**5,912**
32	Book Depreciation	73,521	51,079	14,489	1,128	798	1,136	4,892
33	Taxes Other Than Income Taxes	22,060	11,628	5,761	602	524	836	2,710
34	Prov For Deferred Inc Taxes	5,788	3,770	1,276	107	72	100	463
35	Net Investment Tax Credit	-106	-70	-21	-2	-2	-3	-8
36	**Total Operating Expense**	**570,932**	**340,214**	**160,368**	**17,664**	**33,909**	**4,809**	**13,968**
37	State and Federal Income Taxes	1,006	-363	2,190	302	681	329	-2,132
38	**Total Expense**	**571,938**	**339,851**	**162,558**	**17,965**	**34,590**	**5,138**	**11,836**
39	AFUDC (Rev Credit)	2,677	1,563	706	70	17	36	284
40	**Total Operating Income**	**52,776**	**29,553**	**18,202**	**2,023**	**3,064**	**2,342**	**-2,409**
41	**Rate Base**	**1,267,863**	**831,992**	**255,658**	**22,148**	**18,710**	**29,507**	**109,847**
42	**Present Return on Rate Base**	**4.16%**	**3.55%**	**7.12%**	**9.13%**	**16.38%**	**7.94%**	**-2.19%**
43	**Present Return on Common Equity**	**3.89%**	**2.73%**	**9.52%**	**13.36%**	**27.16%**	**11.08%**	**-8.21%**
44	**Required Return on Rate Base**	**7.48%**	**7.48%**	**7.48%**	**7.48%**	**7.48%**	**7.48%**	**7.48%**
45	**Required Operating Income**	**94,836**	**62,233**	**19,123**	**1,657**	**1,399**	**2,207**	**8,217**
46	**Income Deficiency**	**42,060**	**32,680**	**921**	**-366**	**-1,665**	**-135**	**10,625**
47	**Revenue Deficiency**	**59,026**	**45,538**	**1,936**	**-423**	**-2,137**	**-69**	**14,181**
48	**Deficiency / Pres Retail Revenue**	**9.55%**	**12.48%**	**1.08%**	**-2.13%**	**-5.68%**	**-0.94%**	**161.45%**

Class Cost of Service Study ($000); Test Year 2024

Docket No. G002/GR-23-413
Exhibit___(CJB-1), Schedule 3

SUMMARY

Equal Return vs Present

	Operating Revenue Requirement	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Return On Rate Base	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%
2	Equalized Total Retail Rev	676,832	410,438	181,246	19,423	35,455	7,305	22,964
3	Present Total Retail Revenue	617,806	364,900	179,310	19,847	37,592	7,374	8,783
4	Revenue Deficiency	59,026	45,538	1,936	-423	-2,137	-69	14,181
5	Deficiency / Pres Total Retail Rev	9.55%	12.48%	1.08%	-2.13%	-5.68%	-0.94%	161.45%
	Internal Retail Revenue Reqt							
6	Customer Retail Revenue Requirement	143,160	127,894	14,424	271	501	54	16
7	Average Monthly Customers	490,675	453,981	36,278	147	235	26	9
8	Revenue Requirement $ / Mo / Cust	24.31	23.48	33.13	153.76	177.61	173.30	147.06
9	Capacity Retail Revenue Requirement	144,289	70,871	40,989	4,392	3,133	5,079	19,824
10	Annual Dkt Sales	118,778,662	39,670,184	23,667,033	2,968,555	8,003,112	12,284,918	32,184,860
11	Revenue Requirement $ / Dkt	1.21	1.79	1.73	1.48	0.39	0.41	0.62
	Capacity - Sub Classification							
12	Capacity - Base Revenue Requirement	40,680	15,026	9,041	1,138	3,133	4,677	7,664
13	Capacity - Seasonal Revenue Requirement	71,515	38,885	22,115	2,211	0	196	8,108
14	Peak Shaving Revenue Requirement	32,094	16,961	9,833	1,042	0	207	4,052
15	Base Rev Requirement $ / Dkt	0.34	0.38	0.38	0.38	0.39	0.38	0.24
16	Seasonal Rev Requirement $ / Dkt	0.60	0.98	0.93	0.74	0.00	0.02	0.25
17	Peak Shave Rev Requirement $ / Dkt	0.27	0.43	0.42	0.35	0.00	0.02	0.13
18	Energy Retail Revenue Requirement	38,792	18,182	11,085	1,378	3,710	2,172	2,265
19	Revenue Requirement $ / Dkt	0.33	0.46	0.47	0.46	0.46	0.18	0.07
20	Total Internal Retail Revenue Requirement	326,240	216,948	66,498	6,041	7,344	7,305	22,104
21	Revenue Requirement $ / Dkt	2.75	5.47	2.81	2.03	0.92	0.59	0.69
22	Revenue Requirement $ / Mo / Cust	55.41	39.82	152.75	3,430.34	2,605.21	23,413.91	204,668.79
	External Retail Revenue Reqt							
23	Capacity Revenue Requirement	79,684	48,191	28,441	2,950	0	0	102
24	Energy Revenue Requirement	270,750	145,153	86,297	10,432	28,111	0	757
25	Total External Revenue Requirement	350,434	193,344	114,738	13,382	28,111	0	860
26	Cap Revenue Requirement $ / Dkt	0.67	1.21	1.20	0.99	0.00	0.00	0.00
27	Ener Revenue Requirement $ / Dkt	2.28	3.66	3.65	3.51	3.51	0.00	0.02
28	Tot Revenue Requirement $ / Dkt	2.95	4.87	4.85	4.51	3.51	0.00	0.03
	Total Retail Revenue Reqt							
29	Customer Revenue Requirement	143,160	127,894	14,424	271	501	54	16
30	Capacity Revenue Requirement	223,973	119,062	69,430	7,342	3,133	5,079	19,926
31	Energy Revenue Requirement	309,542	163,336	97,382	11,810	31,820	2,172	3,022
32	Total Revenue Requirement	676,675	410,292	181,236	19,423	35,455	7,305	22,964
33	Customer Revenue Reqt $ / Dkt	1.21	3.22	0.61	0.09	0.06	0.00	0.00
34	Demand Revenue Reqt $ / Dkt	1.89	3.00	2.93	2.47	0.39	0.41	0.62
35	Energy Revenue Reqt $ / Dkt	2.61	4.12	4.11	3.98	3.98	0.18	0.09
36	Total Revenue Reqt $ / Dkt	5.70	10.34	7.66	6.54	4.43	0.59	0.71

Proposed Return vs Present

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
37	Proposed Total Retail Revenue	676,832	402,813	194,178	21,382	40,112	9,459	8,889
38	Revenue Deficiency	59,026	37,913	14,867	1,535	2,520	2,084	105
39	Deficiency / Pres Total Oper Revenue	9.55%	10.39%	8.29%	7.74%	6.70%	28.27%	1.20%

Proposed Return vs Equal

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
40	Revenue Difference	-0.0014	-7,625	12,932	1,959	4,657	2,153	-14,075
41	Difference / Tot Equal Revenue"	0.00%	-1.86%	7.13%	10.08%	13.13%	29.48%	-61.29%

Class Cost of Service Study ($000); Test Year 2024

RATE BASE

	Plant in Service	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	Design Day	75,274	39,991	22,852	2,416	0	485	9,529
2	**Storage Plant (LNG)**	Design Day	94,123	50,006	28,574	3,021	0	606	11,916
3	Transmission - Average Capacity	Average and Peak	113,117	55,594	31,860	3,412	3,126	4,998	14,127
4	Transmission - Direct Assign	Direct Assign	21,306	0	0	0	0	0	21,306
5	**Transmission Plant**		134,424	55,594	31,860	3,412	3,126	4,998	35,433
	Distribution Plant								
6	Regulator Stations	Average and Peak	605	297	170	18	17	27	76
7	Mains - Minimum System	Modified Customers	424,906	393,132	31,415	127	203	23	6
8	Mains - Average Capacity	Modified Sales W/Transport	224,696	85,023	50,724	6,362	17,153	26,330	39,104
9	Mains - Excess Capacity	Excess Design Day	395,992	220,028	124,097	12,359	0	1,098	38,411
10	Mains - Total		1,045,593	698,182	206,236	18,848	17,356	27,450	77,521
11	Services	Service Study	386,499	335,074	49,304	539	1,444	110	29
12	Meters	Meter & Regul Study	147,691	118,386	26,843	838	1,371	204	49
13	House Regulators	Meter & Regul Study	31,250	25,050	5,680	177	290	43	10
14	Total Distribution Plant		1,611,639	1,176,990	288,233	20,420	20,478	27,833	77,685
15	**General Plant**	Prod-Stor-Tran-Dis	272,283	188,005	52,812	4,161	3,355	4,822	19,128
16	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
17	**Gas Plant in Service**		**2,187,742**	**1,510,586**	**424,332**	**33,430**	**26,959**	**38,745**	**153,691**

	Accum Depr Reserve	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
18	**Production Plant (LPG)**	Design Day	19,856	10,549	6,028	637	0	128	2,514
19	**Storage Plant (LNG)**	Design Day	45,901	24,386	13,935	1,473	0	296	5,811
20	Transmission - Average Capacity	Average and Peak	27,181	13,358	7,656	820	751	1,201	3,394
21	Transmission - Direct Assign	Direct Assign	5,687	0	0	0	0	0	5,687
22	**Transmission Plant**		32,868	13,358	7,656	820	751	1,201	9,082
	Distribution Plant								
23	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
24	Mains	Mains, Overall	261,584	174,669	51,596	4,715	4,342	6,867	19,394
25	Services	Service Study	215,251	186,611	27,458	300	804	61	16
26	Meters	Meter & Regul Study	81,537	65,359	14,820	462	757	113	27
27	House Regulators	Meter & Regul Study	6,981	5,596	1,269	40	65	10	2
28	Total Distribution Plant		565,353	432,235	95,142	5,518	5,968	7,051	19,439
29	**General Plant**	Prod-Stor-Tran-Dis	121,351	83,790	23,537	1,854	1,495	2,149	8,525
30	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
31	**Total Accum Depr**		**785,328**	**564,318**	**146,298**	**10,302**	**8,214**	**10,824**	**45,370**
32	**Net Plant**		**1,402,415**	**946,267**	**278,034**	**23,128**	**18,745**	**27,921**	**108,320**

	Subtractions to Net Plant	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
	Accum Deferred Inc Tax								
33	**Production Plant (LPG)**	Design Day	-247	-131	-75	-8	0	-2	-31
34	**Storage Plant (LNG)**	Design Day	1,745	927	530	56	0	11	221
35	Transmission - Average Capacity	Average and Peak	16,401	8,060	4,619	495	453	725	2,048
36	Transmission - Direct Assign	Direct Assign	3,877	0	0	0	0	0	3,877
37	**Transmission Plant**		20,278	8,060	4,619	495	453	725	5,926
	Distribution Plant								
38	Regulator Stations	Average and Peak	12	6	3	0	0	1	1
39	Mains	Mains, Overall	91,862	61,340	18,119	1,656	1,525	2,412	6,811
40	Services	Service Study	54,838	47,542	6,995	76	205	16	4
41	Meters	Meter & Regul Study	22,547	18,074	4,098	128	209	31	7
42	House Regulators	Meter & Regul Study	2,852	2,286	518	16	26	4	1
43	Total Distribution Plant		172,111	129,247	29,734	1,877	1,966	2,463	6,825
44	**General Plant**	Prod-Stor-Tran-Dis	19,604	13,536	3,802	300	242	347	1,377
45	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
46	Net Operating Loss (NOL) Carry Forward	Net Plant	0	0	0	0	0	0	0
47	Non-Plant Related	Labor	1,048	776	168	14	12	17	62
48	**Total Subtractions**		**214,540**	**152,415**	**38,779**	**2,733**	**2,673**	**3,561**	**14,379**

Class Cost of Service Study ($000); Test Year 2024

RATE BASE

Additions to Net Plant

	CWIP	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Production Plant (LPG)	Design Day	5,656	3,005	1,717	182	0	36	716
2	Storage Plant (LNG)	Design Day	11,699	6,215	3,552	376	0	75	1,481
3	Transmission - Average Capacity	Average and Peak	872	428	245	26	24	39	109
4	Transmission - Direct Assign	Direct Assignment	0	0	0	0	0	0	0
5	Transmission Plant		872	428	245	26	24	39	109
6	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
7	Mains	Mains Overall	5,171	3,453	1,020	93	86	136	383
8	Services	Service Study	6	5	1	0	0	0	0
9	Meters	Meter & Regul Study	0	0	0	0	0	0	0
10	House Regulators	Meter & Regul Study	179	144	33	1	2	0	0
11	General & Common Plant	Prod-Stor-Tran-Dis	10,543	7,279	2,045	161	130	187	741
12	Total CWIP		34,124	20,529	8,612	839	242	473	3,430
13	**Materials & Supplies**	Tran & Distrib	2,318	1,637	425	32	31	44	150
	Gas In Storage								
14	Total Gas in Storage	Sales, W/ Transp	43,755	14,614	8,718	1,094	2,948	4,525	11,856
15	**Non-Plant Assets & Liab**	Labor	7,968	5,896	1,281	104	91	127	470
	Miscellaneous	**Allocator**							
16	Prepay: Insurance	Tran & Distrib	0	0	0	0	0	0	0
17	Prepay: Miscellaneous	Tran & Distrib	1,820	1,285	334	25	25	34	118
18	Fuel	Sales, W/o Transp	0	0	0	0	0	0	0
19	Total Miscellaneous		1,820	1,285	334	25	25	34	118
	Working Cash								
20	Total Working Cash	Modified O&M Expense	-9,998	-5,820	-2,966	-339	-699	-56	-118
21	**Total Additions**		**79,988**	**38,140**	**16,403**	**1,753**	**2,638**	**5,148**	**15,906**
22	**Total Rate Base**		**1,267,863**	**831,992**	**255,658**	**22,148**	**18,710**	**29,507**	**109,847**
23	**Common Rate Base (@ 52.50%)**		**665,628**	**436,796**	**134,220**	**11,628**	**9,823**	**15,491**	**57,670**
24	Customer Component		543,627	484,737	56,514	743	1,425	167	41
25	Demand Component		686,643	335,984	192,413	20,553	14,985	24,816	97,894
26	Energy Component		37,592	11,272	6,731	853	2,300	4,525	11,912

Class Cost of Service Study ($000); Test Year 2024

INCOME STATEMENT

Operating Revenue (Cal Month)

	Retail Revenue	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1a	**Present Retail Rev**	Direct Assign	**617,806**	**364,900**	**179,310**	**19,847**	**37,592**	**7,374**	**8,783**
1b	**Proposed Retail Rev**	Direct Assign	**676,675**	**402,667**	**194,167**	**21,382**	**40,111**	**9,459**	**8,889**
2	**Retail Rev Increase**		**58,868**	**37,767**	**14,857**	**1,535**	**2,519**	**2,084**	**105**
	Other Operating Revenue								
3	Late Pay Penalties	Late Pay; Mod Pres Rev	1,652	1,532	109	4	6	0	0
4	Connection Charges	Customers	317	293	23	0	0	0	0
5	Return Check Charges	Customers	38	35	3	0	0	0	0
6	Connect Smart	Customers	28	26	2	0	0	0	0
7	Interchange Gas	Design Day	434	230	132	14	0	3	55
8	Damage Claim	Design Day	425	226	129	14	0	3	54
9	Ltd Firm Sales - Rsrvs & Vols	Design Day	193	103	59	6	0	1	24
10	Distribution Other	Customers	0	0	0	0	0	0	0
11	Miscellaneous Other	1/2 Dsgn Day, 1/2 Ener	1,144	495	288	33	39	63	227
12	**Tot Other Oper Rev - Pres**		**4,230**	**2,940**	**744**	**71**	**45**	**70**	**361**
13	Incr Late Pay - Proposed	Late Pay; Mod Pres Rev	157	146	10	0	1	0	0
14	Incr Connection Charge Revenue - Propose	Customers	0	0	0	0	0	0	0
15	**Tot Other Oper Rev - Prop**		**4,387**	**3,086**	**755**	**71**	**45**	**70**	**361**
16a	**Total Oper Rev - Present**		**622,037**	**367,840**	**180,055**	**19,918**	**37,636**	**7,444**	**9,144**
16b	**Total Oper Rev - Proposed**		**681,062**	**405,753**	**194,922**	**21,453**	**40,156**	**9,528**	**9,249**
17	**Operating Rev Increase**		**59,026**	**37,913**	**14,867**	**1,535**	**2,520**	**2,084**	**105**

Operation & Maintenance (Pg 1 of 2)

	Purchased Gas Expense	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
18	Commodity	Direct Assign	270,750	145,153	86,297	10,432	28,111	0	757
19	Demand	Direct Assign	79,684	48,191	28,441	2,950	0	0	102
20	Propane	Design Day	0	0	0	0	0	0	0
21	Limited Firm	Design Day	0	0	0	0	0	0	0
22	Total Purchases		350,434	193,344	114,738	13,382	28,111	0	860
	Other Production Expense								
23	Other Purchased Gas	Design Day	1,226	651	372	39	0	8	155
24	MN Gas MGP Clean Up	Sales, W/o Transp	1,020	543	324	41	110	0	3
25	Misc. LPG Op Exp	Design Day	3,419	1,817	1,038	110	0	22	433
26	Misc. LNG Op Exp	1/2 Dsgn Day, 1/2 Ener	2,262	979	569	65	76	124	450
27	Total Other Production Expense		7,927	3,990	2,303	254	186	154	1,041
28	Transmission - Average Capacity	Average and Peak	623	306	175	19	17	28	78
29	Transmission - Other	Other	0	0	0	0	0	0	0
30	**Transmission Expense**		623	306	175	19	17	28	78
	Distribution Expense								
31	Regulator Stations	Average and Peak	525	258	148	16	15	23	66
32	Mains	Mains, Overall	15,402	10,285	3,038	278	256	404	1,142
33	Services	Service Study	3,011	2,610	384	4	11	1	0
34	Meters	Meter & Regul Study	-5,571	-4,466	-1,013	-32	-52	-8	-2
35	House Regulators	Meter & Regul Study	3,756	3,010	683	21	35	5	1
36	Rents	Customers	1,111	1,028	82	0	1	0	0
37	Dispatching	1/2 Dsgn Day, 1/2 Ener	3,009	1,302	756	86	101	165	598
38	Customer Installations	Customers	850	787	63	0	0	0	0
39	Other Distribution	Customers	9,573	8,857	708	3	5	1	0
40	Supervision & Engineering	Dist Exp, w/o Sup & Eng	7,887	5,896	1,208	94	93	147	450
41	Total Distribution Expense		39,553	29,567	6,057	471	464	739	2,255

Class Cost of Service Study ($000); Test Year 2024

INCOME STATEMENT

Operation & Maintenance (Pg 2 of 2)

	Cust Acctg & Inform	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Acct Superv	Customers	1,346	1,245	100	0	1	0	0
2	Acct Meter Read	Customers	2,365	2,188	175	1	1	0	0
3	Acct Recrds & Coll	Record & Coll Study	6,140	5,443	398	106	169	19	6
4	Acct Uncollect	Uncollectibles Study	2,958	2,489	469	0	0	0	0
5	Acct Misc	Customers	77	72	6	0	0	0	0
6	Asst Expense (w/o CIP)	Cust Inform Study	910	669	204	13	21	2	1
7	Tot Cust Acctg & Inform		13,797	12,107	1,351	120	191	21	7
	Admin & General								
8	Property Insurance	Net Plant	748	505	148	12	10	15	58
9	Pension & Benefit-Direct	Labor	8,817	6,524	1,417	115	101	141	520
10	Salaries	Labor	7,320	5,416	1,176	95	84	117	432
11	Office & Supplies	Labor	4,592	3,398	738	60	52	73	271
12	Admin Transfer Credit	Labor	-5,649	-4,180	-908	-73	-65	-90	-333
13	Outside Services	Labor	1,571	1,163	253	20	18	25	93
14	Incentive Compensation	Labor	0	0	0	0	0	0	0
15	Injuries and Claims	1/2 Rt Base, 1/2 Pres Rev;	1,778	1,109	437	44	67	31	90
16	Regulatory Comm Exp	Pres Rev; Mod Pres Rev	679	401	197	22	41	8	10
17	Contributions	Pres Rev; Mod Pres Rev	0	0	0	0	0	0	0
18	General Advertising	1/2 Rt Base, 1/2 Pres Rev;	24	15	6	1	1	0	1
19	Misc General Exp	1/2 Rt Base, 1/2 Pres Rev;	195	122	48	5	7	3	10
20	Rents	1/2 Rt Base, 1/2 Pres Rev;	7,410	4,620	1,822	184	280	130	374
21	Maint of Gen Plt	1/2 Rt Base, 1/2 Pres Rev;	64	40	16	2	2	1	3
22	Total A & G Expense		27,550	19,131	5,351	485	599	456	1,527
	Amortizations								
23	CIP/DSM	Sales, W/o CIP Exempt	28,618	14,547	8,676	1,078	2,923	1,320	74
24	Amortizations	Labor	926	685	149	12	11	15	55
25	Instructional Advertising	Pres Rev; Mod Pres Rev	192	113	56	6	12	2	3
26	Total Amortizations		29,736	15,345	8,880	1,097	2,945	1,338	131
	Sales Expense								
27	Sales, Econ Dvlp & Other	Sales, W/ Transp	50	17	10	1	3	5	14
28	Total Sales Econ Dvlp & Other		50	17	10	1	3	5	14
29	**Total O&M Expense**		**469,670**	**273,807**	**138,865**	**15,829**	**32,517**	**2,741**	**5,912**

Book Depreciation

		Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
30	**Production Plant (LPG)**	Design Day	4,793	2,546	1,455	154	0	31	607
31	**Storage Plant (LNG)**	Design Day	4,058	2,156	1,232	130	0	26	514
32	Transmission - Average Capacity	Average and Peak	2,058	1,011	580	62	57	91	257
33	Transmission - Direct Assign	Direct Assign	362	0	0	0	0	0	362
34	**Transmission Plant**		2,420	1,011	580	62	57	91	619
	Distribution Plant								
35	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
36	Mains	Mains, Overall	24,072	16,074	4,748	434	400	632	1,785
37	Services	Service Study	12,959	11,234	1,653	18	48	4	1
38	Meters	Meter & Regul Study	4,895	3,924	890	28	45	7	2
39	House Regulators	Meter & Regul Study	894	717	163	5	8	1	0
40	Total Distribution Plant		42,820	31,949	7,453	485	502	644	1,788
41	**General & Common Plant**	Prod-Stor-Tran-Dis	19,431	13,417	3,769	297	239	344	1,365
42	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
43	**Total Book Deprec**		**73,521**	**51,079**	**14,489**	**1,128**	**798**	**1,136**	**4,892**

Class Cost of Service Study ($000); Test Year 2024

INCOME STATEMENT

	Real Estate & Prop Taxes	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	Design Day	885	470	269	28	0	6	112
2	**Storage Plant (LNG)**	Design Day	0.0	0	0	0	0	0	0
3	Transmission - Average Capacity	Average and Peak	1,088	535	307	33	30	48	136
4	Transmission - Direct Assign	Direct Assignment	205	0	0	0	0	0	205
5	**Transmission Plant**		1,293	535	307	33	30	48	341
	Distribution Plant								
6	Regulator Stations	Average and Peak	16,455	8,087	4,635	496	455	727	2,055
7	Mains	Mains, Overall	0	0	0	0	0	0	0
8	Services	Service Study	0	0	0	0	0	0	0
9	Meters	Meter & Regul Study	0	0	0	0	0	0	0
10	House Regulators	Meter & Regul Study	0	0	0	0	0	0	0
11	Total Distribution Plant		16,455	8,087	4,635	496	455	727	2,055
12	**General and Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
13	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
14	**Total Rl Est & Prop Tax**		**18,633**	**9,092**	**5,210**	**558**	**485**	**781**	**2,508**
15	Payroll Taxes	Labor	3,427	2,536	551	45	39	55	202
16	**Tot Non-Income Taxes**		**22,060**	**11,628**	**5,761**	**602**	**524**	**836**	**2,710**
	Provision-Defer Inc Tax	**Allocator**							
17	**Production Plant (LPG)**	Design Day	240	128	73	8	0	2	30
18	**Storage Plant (LNG)**	Design Day	599	318	182	19	0	4	76
19	Transmission - Average Capacity	Average and Peak	651	320	183	20	18	29	81
20	Transmission - Direct Assign	Direct Assign	29	0	0	0	0	0	29
21	**Transmission Plant**		681	320	183	20	18	29	111
	Distribution Plant								
22	Regulator Stations	Average and Peak	1	1	0	0	0	0	0
23	Mains	Mains, Overall	341	228	67	6	6	9	25
24	Services	Service Study	-398	-345	-51	-1	-1	0	0
25	Meters	Meter & Regul Study	1,012	812	184	6	9	1	0
26	House Regulators	Meter & Regul Study	160	128	29	1	1	0	0
27	Total Distribution Plant		1,117	823	230	12	15	11	26
28	**General and Common Plant**	Prod-Stor-Tran-Dis	3,039	2,098	589	46	37	54	213
29	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
30	Net Operating Loss (NOL) Carry Forward	Net Plant	0	0	0	0	0	0	0
31	Non-Plant Related	Labor	112	83	18	1	1	2	7
32	**Tot Prov Defer Inc Tax**		**5,788**	**3,770**	**1,276**	**107**	**72**	**100**	**463**
	Investment Tax Credit	**Allocator**							
33	**Production Plant (LPG)**	Design Day	0	0	0	0	0	0	0
34	**Storage Plant (LNG)**	Design Day	-1	0	0	0	0	0	0
35	Transmission - Average Capacity	Average and Peak	-5	-2	-1	0	0	0	-1
36	Transmission - Direct Assign	Direct Assign	0	0	0	0	0	0	0
37	**Transmission Plant**		-5	-2	-1	0	0	0	-1
	Distribution Plant								
38	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
39	Mains	Mains, Overall	-101	-67	-20	-2	-2	-3	-7
40	Services	Service Study	0	0	0	0	0	0	0
41	Meters	Meter & Regul Study	0	0	0	0	0	0	0
42	House Regulators	Meter & Regul Study	0	0	0	0	0	0	0
43	Total Distribution Plant		-101	-67	-20	-2	-2	-3	-7
44	**General and Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
45	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
46	**Net Invest Tax Credit**		**-106**	**-70**	**-21**	**-2**	**-2**	**-3**	**-8**
47	**Total Operating Exp**		**570,932**	**340,214**	**160,368**	**17,664**	**33,909**	**4,809**	**13,968**
42a	**Pres Op Inc Before Inc Tax**		**51,105**	**27,627**	**19,686**	**2,254**	**3,727**	**2,635**	**-4,824**
42b	**Prop Op Inc Before Inc Tax**		**110,130**	**65,540**	**34,554**	**3,789**	**6,247**	**4,719**	**-4,719**

Class Cost of Service Study ($000); Test Year 2024

	Tax Deprec & Removal	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	Design Day	5,994	3,184	1,820	192	0	39	759
2	**Storage Plant (LNG)**	Design Day	6,170	3,278	1,873	198	0	40	781
3	Transmission - Average Capacity	Average and Peak	4,587	2,254	1,292	138	127	203	573
4	Transmission - Direct Assign	Direct Assign	537	0	0	0	0	0	537
5	**Transmission Plant**		5,124	2,254	1,292	138	127	203	1,110
	Distribution Plant								
6	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
7	Mains	Mains, Overall	34,141	22,798	6,734	615	567	896	2,531
8	Services	Service Study	8,514	7,382	1,086	12	32	2	1
9	Meters	Meter & Regul Study	8,054	6,456	1,464	46	75	11	3
10	House Regulators	Meter & Regul Study	1,221	979	222	7	11	2	0
11	Total Distribution Plant		51,931	37,614	9,506	680	685	912	2,535
12	**General and Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
13	**Common Plant**	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
14	Net Operating Loss (NOL) Carry Forward	Net Plant	34,159	23,049	6,772	563	457	680	2,638
15	**Total Tax Depreciation**		**103,378**	**69,379**	**21,263**	**1,772**	**1,268**	**1,873**	**7,823**
	Present Return								
	Inc Tax Additions	**Allocator**							
16	Total Book Depr Exp		73,521	51,079	14,489	1,128	798	1,136	4,892
17	Provision for Deferred		5,788	3,770	1,276	107	72	100	463
18	Net Inv Tax Credit		-106	-70	-21	-2	-2	-3	-8
19	Avoided Tax Interest	CWIP	1,382	831	349	34	10	19	139
20	Total Tax Additions		80,584	55,610	16,092	1,267	878	1,252	5,485
	Inc Tax Deductions								
21	Tax Depr & Removal Exp		103,378	69,379	21,263	1,772	1,268	1,873	7,823
22	Debt Interest Expense	; Mod Rate Base	26,879	17,638	5,420	470	397	626	2,329
23	Other Timing Differences	Labor	-3,069	-2,271	-493	-40	-35	-49	-181
24	Meals	Labor	104	77	17	1	1	2	6
25	Total Tax Deductions		127,292	84,824	26,206	2,203	1,631	2,451	9,977
26a	**Pres Taxable Net Income**		**4,397**	**-1,587**	**9,572**	**1,318**	**2,975**	**1,436**	**-9,316**
26b	**Prop Taxable Net Income**		**63,423**	**36,326**	**24,439**	**2,853**	**5,495**	**3,520**	**-9,211**
27a	**Pres Inc Tax, @22.88%**		**1,006**	**-363**	**2,190**	**302**	**681**	**329**	**-2,132**
27b	**Prop Inc Tax, @28.34%**		**17,971**	**10,293**	**6,925**	**808**	**1,557**	**998**	**-2,610**
28a	**Pres Preliminary Return**		50,099	27,990	17,496	1,953	3,047	2,306	-2,693
28b	**Prop Preliminary Return**		92,159	55,246	27,629	2,981	4,691	3,721	-2,109
29	**Total AFUDC**	CWIP	**2,677**	**1,563**	**706**	**70**	**17**	**36**	**284**
30a	**Pres Total Return**	; Mod Rate Base	**52,776**	**29,553**	**18,202**	**2,023**	**3,064**	**2,342**	**-2,409**
30b	**Prop Total Return**	; Mod Rate Base	**94,836**	**56,809**	**28,335**	**3,051**	**4,708**	**3,757**	**-1,825**
31a	**Pres % Return on Rate Base**		**4.16%**	**3.55%**	**7.12%**	**9.13%**	**16.38%**	**7.94%**	**-2.19%**
31b	**Prop % Return on Rate Base**		**7.48%**	**6.83%**	**11.08%**	**13.78%**	**25.16%**	**12.73%**	**-1.66%**
32a	**Pres Common Return**		**25,897**	**11,915**	**12,783**	**1,553**	**2,667**	**1,716**	**(4,737)**
32b	**Prop Common Return**		**67,957**	**39,171**	**22,915**	**2,582**	**4,311**	**3,132**	**(4,154)**
33a	**Pres % Ret on Common Rt Bs**		**3.89%**	**2.73%**	**9.52%**	**13.36%**	**27.16%**	**11.08%**	**-8.21%**
33b	**Prop % Ret on Common Rt Bs**		**10.21%**	**8.97%**	**17.07%**	**22.20%**	**43.89%**	**20.22%**	**-7.20%**
	AFUDC								
34	Production Plant (LPG)	Design Day	1,072	570	326	34	0	7	136
35	Storage Plant (LNG)	Design Day	504	268	153	16	0	3	64
36	Transmission - Average Capacity	Average and Peak	155	76	44	5	4	7	19
37	Transmission - Direct Assign	Direct Assign	0	0	0	0	0	0	0
38	Transmission Plant	Average and Peak	155	76	44	5	4	7	19
	Distribution:								
39	Regulator Stations	Average and Peak	0	0	0	0	0	0	0
40	Mains	Mains Overall	347	232	68	6	6	9	26
41	Services	Service Study	1	1	0	0	0	0	0
42	Meters	Meter & Regul Study	0	0	0	0	0	0	0
43	House Regulators	Meter & Regul Study	39	31	7	0	0	0	0
44	Total Distribution		387	264	76	6	6	9	26
45	General Plant	Prod-Stor-Tran-Dis	558	385	108	9	7	10	39
46	Gas Common	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
47	Total AFUDC		2,677	1,563	706	70	17	36	284
	Labor Allocator	**Allocator**							
48	Customer Accounting	Customers	3,830	3,544	283	1	2	0	0
49	Cust Serv & Inform	Customers	753	696	56	0	0	0	0
50	Distribution	Dist Exp, w/o Sup & Eng	23,334	17,443	3,573	278	274	436	1,330
51	Admin & General	Labor w/o A&G	15,438	11,423	2,481	201	176	247	910
52	Production	Other Production Exp	3,966	1,996	1,152	127	93	77	521
53	Sales	Sales, W/ Transp	0	0	0	0	0	0	0
54	Transmission	Design Day	421	223	128	14	0	3	53
55	Total		47,742	35,326	7,673	620	545	763	2,814

Class Cost of Service Study ($000); Test Year 2024

ALLOCATORS

	Internal Allocators	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	1/2 Dsgn Day, 1/2 Ener	**100.00%**	**43.26%**	**25.14%**	**2.85%**	**3.37%**	**5.49%**	**19.88%**
2	1/2 Rt Base, 1/2 Pres Rev; (Only for Class allocations)	**100.00%**	**62.34%**	**24.59%**	**2.48%**	**3.78%**	**1.76%**	**5.04%**
3	Average and Peak (Mains)	620,688	305,051	174,821	18,721	17,153	27,427	77,515
4	Average and Peak	**100.00%**	**49.15%**	**28.17%**	**3.02%**	**2.76%**	**4.42%**	**12.49%**
5	CWIP	**100.00%**	**60.16%**	**25.24%**	**2.46%**	**0.71%**	**1.39%**	**10.05%**
6	Dist Exp, w/o Sup & Eng	31,666	23,671	4,849	377	371	592	1,805
7	Dist Exp, w/o Sup & Eng	**100.00%**	**74.75%**	**15.31%**	**1.19%**	**1.17%**	**1.87%**	**5.70%**
8	Distribution Plant	**100.00%**	**73.03%**	**17.88%**	**1.27%**	**1.27%**	**1.73%**	**4.82%**
9	Gas Plant In Service	**100.00%**	**69.05%**	**19.40%**	**1.53%**	**1.23%**	**1.77%**	**7.03%**
10	Labor	**100.00%**	**73.99%**	**16.07%**	**1.30%**	**1.14%**	**1.60%**	**5.90%**
11	Mains, Overall	**100.00%**	**66.77%**	**19.72%**	**1.80%**	**1.66%**	**2.63%**	**7.41%**
12	Modified O&M Expense	459,328	267,388	136,283	15,566	32,106	2,563	5,422
13	Modified O&M Expense	**100.00%**	**58.21%**	**29.67%**	**3.39%**	**6.99%**	**0.56%**	**1.18%**
14	Net Plant	**100.00%**	**67.47%**	**19.83%**	**1.65%**	**1.34%**	**1.99%**	**7.72%**
15	Other Production Exp	**100.00%**	**50.33%**	**29.05%**	**3.21%**	**2.34%**	**1.95%**	**13.13%**
16	Prod-Stor-Tran-Dis	1,915,459	1,322,581	371,520	29,270	23,604	33,923	134,563
17	Prod-Stor-Tran-Dis	**100.00%**	**69.05%**	**19.40%**	**1.53%**	**1.23%**	**1.77%**	**7.03%**
18	Rate Base	**100.00%**	**65.62%**	**20.16%**	**1.75%**	**1.48%**	**2.33%**	**8.66%**
19	Rt Base, w/o Work Cash	1,277,861	837,813	258,624	22,487	19,409	29,563	109,965
20	Rt Base, w/o Work Cash	**100.00%**	**65.56%**	**20.24%**	**1.76%**	**1.52%**	**2.31%**	**8.61%**
21	Transmission & Distribution	1,746,062	1,232,583	320,094	23,832	23,604	32,832	113,118
22	Tran & Distrib	**100.00%**	**70.59%**	**18.33%**	**1.36%**	**1.35%**	**1.88%**	**6.48%**
23	Labor w/o A&G	32,304	23,903	5,192	420	369	516	1,904
24	Labor w/o A&G	**100.00%**	**73.99%**	**16.07%**	**1.30%**	**1.14%**	**1.60%**	**5.90%**
	Component Allocators							
25	Mod Present Rev	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**
26	Mod Rate Base	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**
27	1/2 Mod Rt Bs, 1/2 Mod Pres Rv	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**

Class Cost of Service Study ($000); Test Year 2024

ALLOCATORS

External Allocators

	Customer-Related	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Bills	5,888,101	5,447,768	435,333	1,761	2,819	312	108
2	Modified Bills	5,888,077	5,447,768	435,333	1,761	2,819	312	84
3	Meter & Regul Weightings		1.00					
4	Meter (Wtd Bills)	6,796,277	5,447,768	1,235,244	38,547	63,096	9,382	2,241
5	Service Weightings		1.00					
6	Service (Wtd Bills)	6,283,854	5,447,768	801,596	8,759	23,471	1,787	472
7	Records & Collect Weightings		1.00					
8	Records & Collect (Wtd Bills)	6,146,025	5,447,768	398,257	105,660	169,140	18,720	6,480
9	Cust Information Weightings		1.00					
10	Cust Information (Wtd Bills)	7,403,799	5,447,768	1,658,191	105,660	168,060	17,640	6,480
11	Customers	100.00%	92.52%	7.39%	0.03%	0.05%	0.01%	0.00%
12	Modified Customers	100.00%	92.52%	7.39%	0.03%	0.05%	0.01%	0.00%
13	Meter & Regul Study	100.00%	80.16%	18.18%	0.57%	0.93%	0.14%	0.03%
14	Service Study	100.00%	86.69%	12.76%	0.14%	0.37%	0.03%	0.01%
15	Record & Coll Study	100.00%	88.64%	6.48%	1.72%	2.75%	0.30%	0.11%
16	Cust Inform Study	100.00%	73.58%	22.40%	1.43%	2.27%	0.24%	0.09%
	Energy-Related							
17	Cal Yr Sales Dkt, W/o Trans	74,524,637	39,670,184	23,667,033	2,968,555	8,003,112	0	215,753
18	Transportation Dkt	44,254,025	0	0	0	0	12,284,918	31,969,107
19	Cal Yr Sales Dkt, W/ Trans	118,778,662	39,670,184	23,667,033	2,968,555	8,003,112	12,284,918	32,184,860
20	CIP Exempt Dkt	40,734,453	0	7,196	27,447	32,025	8,683,903	31,983,882
21	Sales Dkt, W/o CIP Exempt	78,044,208	39,670,184	23,659,837	2,941,107	7,971,087	3,601,015	200,978
22	Sales, W/o Transp	100.00%	53.23%	31.76%	3.98%	10.74%	0.00%	0.29%
23	Sales, W/ Transp	100.00%	33.40%	19.93%	2.50%	6.74%	10.34%	27.10%
24	Sales, W/o CIP Exempt	100.00%	50.83%	30.32%	3.77%	10.21%	4.61%	0.26%
25	Modified Sales W/Transport	100.00%	37.84%	22.57%	2.83%	7.63%	11.72%	17.40%
	Demand-Related							
26	Design Day Demand (Retail)	898,926	477,582	272,900	28,854	0	5,790	113,800
27	Avg Daily Firm Dkt, W/ Trans	273,201	108,685	64,841	8,133	0	3,950	87,591
28	Design Day	100.00%	53.13%	30.36%	3.21%	0.00%	0.64%	12.66%
29	Excess Design Day	100.00%	55.56%	31.34%	3.12%	0.00%	0.28%	9.70%
	Miscellaneous (only alloc to class, not component)							
30	Present Retail Revenue	617,806	364,900	179,310	19,847	37,592	7,374	8,783
31	Uncollectibles Study	100.00%	84.15%	15.85%	0.00%	0.00%	0.00%	0.00%
32	Present Retail Revenue	100.00%	59.06%	29.02%	3.21%	6.08%	1.19%	1.42%
33	Late Payment Penalty	100.00%	92.77%	6.61%	0.26%	0.36%	0.00%	0.00%

Class Cost of Service Study ($000); Test Year 2024

Capital Structure		Rate	Ratio	Wtd Cost
1	Long Term Debt	4.46%	46.87%	2.09%
2	Short Term Debt	5.01%	0.63%	0.03%
3	Debt Total	4.46%	47.50%	2.12%
4	Preferred Stock	0.00%	0.00%	0.00%
5	Common Equity	10.20%	52.50%	5.36%
6	Required Rate of Return		100.00%	7.48%
7	MN Combined State & Fed Tax Rate	28.34%		
8	1 / (1 - Tax Rate) Factor	139.54%		
9	Tax Rate / (1 - Tax Rate) Factor	39.54%		

Pipe Material	Diameter	Pipe Type	Footage	Total Cost Normalized 2023	2023 Normalized Cost per Foot	Total Cost Assuming Cost of 2 inch Plastic or Steel Pipe
Plastic	<=2"	Main Gas Plastic <=2"	38,482,840	$584,300,295	**$15.18**	$584,300,295
	> 2" to 4"	Main Gas Plastic > 2" to 4"	10,118,637	$278,978,516	$27.57	$153,635,298
	> 4" to 8"	Main Gas Plastic > 4" to 8"	2,501,382	$104,681,656	$41.85	$37,979,480
	>12" to 20"	Main Gas Plastic >12" to 20"	1,206	$28,085	$23.29	$18,311
Steel	<=2"	Main Gas Steel <=2"	1,413,199	$100,319,424	**$70.99**	$100,319,424
	> 2" to 4"	Main Gas Steel > 2" to 4"	1,999,005	$202,266,475	$101.18	$141,904,311
	> 4" to 8"	Main Gas Steel > 4" to 8"	1,445,191	$304,472,902	$210.68	$102,590,455
	> 8" to 10"	Main Gas Steel > 8" to 10"	231,210	$43,200,696	$186.85	$16,413,013
	>10" to 12"	Main Gas Steel >10" to 12"	429,580	$157,171,177	$365.87	$30,494,798
	>12" to 20"	Main Gas Steel >12" to 20"	182,754	$160,836,655	$880.07	$12,973,244
Total			**56,805,004**	**$1,936,255,881**	**$34.09**	**$1,180,628,630**

Type	Footage	Share
Plastic	51,104,065	89.96%
Steel	5,700,939	10.04%
Total	**56,805,004**	**100%**

Minimum System % Unadjusted >>>	**61.0%**
Demand Adjustment >>>	**20.3%**
Minimum System % Adjusted >>>	**40.6%**

Demand Adjustment

Xcel Energy Demand Adjustment

Class	**Demand (Dth)**	**Customers**	**Demand Adjustment (Dth/day/customer)**	**Minimum**
Residential	477,582	453,981	0.373	169,232
Small Commercial	72,187	24,758	0.373	9,229
Large Commercial	200,713	11,520	0.373	4,294
Small Demand	1,407	14	0.373	5
Large Demand	27,447	133	0.373	49
Firm Transport	5,790	9	0.373	3
Generation Demand	113,800	3	0.373	1
Total	**898,926**			**182,815**

	Demand Adjustment
Two-Inch System (Dth)	182,815
Design Day Demand (Dth)	898,926
	20.3%

Revenue Decoupling Mechanism Model

Residential

TY 2024 Therms and Customers	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Therms	75,759,750	64,558,836	51,527,480	27,653,378	15,237,739	8,703,128	6,605,835	6,953,629	8,872,182	22,918,404	42,380,778	65,530,700	396,701,840
Customers	452,487	452,920	453,346	453,551	453,738	453,534	453,438	453,753	454,071	454,951	455,680	456,299	453,981
Distribution Charge	$0.376599	$0.376599	$0.376599	$0.376599	$0.376599	$0.376599	$0.376599	$0.376599	$0.376599	$0.376599	$0.376599	$0.376599	
Customer Charge	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00	
TY 2024 Revenue	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Distribution Charge Revenue	$28,531,046	$24,312,793	$19,405,197	$10,414,234	$5,738,517	$3,277,589	$2,487,751	$2,618,730	$3,341,255	$8,631,048	$15,960,559	$24,678,796	$149,397,516
Customer Charge Revenue	$4,977,357	$4,982,121	$4,986,806	$4,989,063	$4,991,119	$4,988,873	$4,987,813	$4,991,283	$4,994,783	$5,004,465	$5,012,481	$5,019,289	$59,925,453
Distribution + Cust Chg Revenue	$33,508,403	$29,294,914	$24,392,004	$15,403,298	$10,729,636	$8,266,462	$7,475,564	$7,610,013	$8,336,038	$13,635,513	$20,973,039	$29,698,085	$209,322,969
CCRC Revenue @ 0.036669/therm	$2,778,052	$2,367,323	$1,889,473	$1,014,028	$558,756	$319,137	$242,231	$254,984	$325,336	$840,400	$1,554,070	$2,402,960	$14,546,750
Dist + Cust Chg Revenue w/o CCRC	$30,730,351	$26,927,591	$22,502,531	$14,389,270	$10,170,880	$7,947,325	$7,233,333	$7,355,028	$8,010,702	$12,795,113	$19,418,969	$27,295,125	$194,776,219
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
FRC (Fixed Revenue per Customer) - TY 2024	$67.91	$59.45	$49.64	$31.73	$22.42	$17.52	$15.95	$16.21	$17.64	$28.12	$42.62	$59.82	
FDC (Fixed Distribution Charge) - TY 2024	$0.405629	$0.417102	$0.436709	$0.520344	$0.667480	$0.913157	$1.094991	$1.057725	$0.902901	$0.558290	$0.458202	$0.416524	

Northern States Power Company
State of Minnesota Gas Jurisdiction

Docket No. G002/GR-23-413
Exhibit___(CJB-1), Schedule 6

Revenue Decoupling Mechanism Model

Small Commercial & Industrial

TY 2024 Therms and Customers	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Therms	11,138,465	9,246,722	6,958,194	4,128,972	2,294,018	1,076,914	695,998	812,718	1,053,682	2,692,029	5,665,408	9,641,162	55,404,283
Customers	24,768	24,809	24,840	24,842	24,829	24,814	24,679	24,683	24,688	24,692	24,697	24,757	24,758
Distribution Charge	$0.278538	$0.278538	$0.278538	$0.278538	$0.278538	$0.278538	$0.278538	$0.278538	$0.278538	$0.278538	$0.278538	$0.278538	
Customer Charge	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	
TY 2024 Revenue	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Distribution Charge Revenue	$3,102,486	$2,575,563	$1,938,121	$1,150,076	$638,971	$299,962	$193,862	$226,373	$293,490	$749,832	$1,578,031	$2,685,430	$15,432,198
Customer Charge Revenue	$743,051	$744,257	$745,199	$745,258	$744,874	$744,410	$740,369	$740,498	$740,630	$740,757	$740,897	$742,723	$8,912,922
Distribution + Cust Chg Revenue	$3,845,537	$3,319,820	$2,683,320	$1,895,333	$1,383,845	$1,044,372	$934,231	$966,870	$1,034,120	$1,490,589	$2,318,928	$3,428,153	$24,345,120
CIP Exempt Therms	13	81	414	280	1,156	651	875	178	351	23	10	12	4,045
CCRC Related Therms	11,138,452	9,246,641	6,957,780	4,128,692	2,292,861	1,076,263	695,123	812,541	1,053,330	2,692,006	5,665,398	9,641,150	55,400,238
CCRC Revenue @ 0.036669/therm	$408,438	$339,067	$255,136	$151,396	$84,077	$39,466	$25,490	$29,795	$38,625	$98,714	$207,746	$353,534	$2,031,484
Dist + Cust Chg Revenue w/o CCRC	$3,437,099	$2,980,753	$2,428,184	$1,743,937	$1,299,768	$1,004,906	$908,741	$937,075	$995,495	$1,391,875	$2,111,182	$3,074,620	$22,313,636
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
FRC (Fixed Revenue per Customer) - TY 2024	$138.77	$120.15	$97.75	$70.20	$52.35	$40.50	$36.82	$37.96	$40.32	$56.37	$85.48	$124.19	
FDC (Fixed Distribution Charge) - TY 2024	$0.308579	$0.322358	$0.348968	$0.422366	$0.566590	$0.933135	$1.305666	$1.153014	$0.944778	$0.517036	$0.372644	$0.318905	

Northern States Power Company
State of Minnesota Gas Jurisdiction

Revenue Decoupling Mechanism Model

Large Commercial & Industrial

TY 2024 Therms and Customers	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Therms	31,140,152	28,805,166	23,352,291	11,794,342	7,094,051	5,769,912	3,591,560	3,992,616	5,039,704	12,173,934	19,934,197	28,578,124	181,266,049
Customers	11,431	11,425	11,423	11,421	11,423	11,311	11,633	11,627	11,625	11,638	11,636	11,644	11,520
Distribution Charge	$0.265771	$0.265771	$0.265771	$0.265771	$0.265771	$0.265771	$0.265771	$0.265771	$0.265771	$0.265771	$0.265771	$0.265771	
Customer Charge	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	
TY 2024 Revenue	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Distribution Charge Revenue	$8,276,149	$7,655,578	$6,206,362	$3,134,594	$1,885,393	$1,533,475	$954,532	$1,061,122	$1,339,407	$3,235,479	$5,297,931	$7,595,237	$48,175,259
Customer Charge Revenue	$571,548	$571,242	$571,140	$571,039	$571,140	$565,548	$581,671	$581,360	$581,257	$581,879	$581,775	$582,190	$6,911,790
Distribution + Cust Chg Revenue	$8,847,697	$8,226,820	$6,777,502	$3,705,633	$2,456,533	$2,099,024	$1,536,204	$1,642,482	$1,920,664	$3,817,357	$5,879,707	$8,177,427	$55,087,049
CIP Exempt Therms	2,848	3,186	5,831	9,148	9,911	8,463	11,128	5,728	4,200	2,613	2,385	2,475	67,914
CCRC Related Therms	31,137,304	28,801,980	23,346,460	11,785,194	7,084,140	5,761,449	3,580,432	3,986,888	5,035,505	12,171,320	19,931,812	28,575,650	181,198,135
CCRC Revenue @ 0.036669/therm	$1,141,781	$1,056,146	$856,097	$432,154	$259,770	$211,268	$131,292	$146,196	$184,648	$446,313	$730,884	$1,047,847	$6,644,396
Dist + Cust Chg Revenue w/o CCRC	$7,705,916	$7,170,674	$5,921,405	$3,273,479	$2,196,763	$1,887,756	$1,404,912	$1,496,286	$1,736,016	$3,371,044	$5,148,822	$7,129,580	$48,442,653
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
FRC - 2024	$674.13	$627.64	$518.38	$286.63	$192.31	$166.90	$120.77	$128.69	$149.33	$289.67	$442.51	$612.31	
FDC - 2024	$0.247459	$0.248937	$0.253569	$0.277547	$0.309663	$0.327172	$0.391170	$0.374763	$0.344468	$0.276907	$0.258291	$0.249477	

Revenue Decoupling Mechanism Model

Demand Billed & Firm Transport

TY 2024 Therms and Customers	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Therms	5,141,964	4,737,893	4,809,367	3,359,116	2,871,648	2,119,080	2,168,082	2,560,837	3,153,385	3,792,257	4,465,673	5,082,877	44,262,179
Customers	157	157	157	157	158	158	158	158	158	158	158	158	158
Distribution Charge	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	
Customer Charge - Small	$175.00	$175.00	$175.00	$175.00	$175.00	$175.00	$175.00	$175.00	$175.00	$175.00	$175.00	$175.00	
Customer Charge - Large	$275.00	$275.00	$275.00	$275.00	$275.00	$275.00	$275.00	$275.00	$275.00	$275.00	$275.00	$275.00	
Customer Charge - Firm Transport	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	
TY 2024 Revenue	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Distribution Charge Revenue	$747,477	$688,738	$699,128	$488,308	$417,446	$308,046	$315,170	$372,264	$458,401	$551,273	$649,166	$738,888	$6,434,304
Customer Charge Revenue	$42,001	$42,037	$42,072	$42,108	$42,144	$42,179	$42,215	$42,250	$42,286	$42,322	$42,357	$42,393	$506,364
Distribution + Cust Chg Revenue	$789,478	$730,775	$741,201	$530,416	$459,589	$350,226	$357,385	$414,514	$500,687	$593,594	$691,523	$781,280	$6,940,668
CIP Exempt Therms	53,411	32,387	33,771	29,646	21,907	26,134	29,738	28,994	26,338	50,595	34,091	48,675	415,687
CCRC Related Therms	5,088,553	4,705,506	4,775,597	3,329,470	2,849,741	2,092,946	2,138,344	2,531,843	3,127,047	3,741,662	4,431,582	5,034,202	43,846,492
CCRC Revenue @ 0.036669/therm	$186,593	$172,547	$175,117	$122,089	$104,498	$76,747	$78,411	$92,841	$114,666	$137,204	$162,503	$184,600	$1,607,817
Dist + Cust Chg Revenue w/o CCRC	$602,885	$558,228	$566,083	$408,327	$355,091	$273,479	$278,973	$321,673	$386,021	$456,391	$529,020	$596,680	$5,332,851
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
FRC - 2024	$3,839.92	$3,552.56	$3,599.59	$2,594.32	$2,254.23	$1,734.70	$1,768.10	$2,037.06	$2,442.55	$2,885.45	$3,341.91	$3,766.25	
FDC - 2024	$0.117248	$0.117822	$0.117704	$0.121558	$0.123654	$0.129055	$0.128673	$0.125613	$0.122415	$0.120348	$0.118464	$0.117390	

Revenue Decoupling Mechanism Model

Small Interruptible

TY 2024 Therms and Customers	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Therms - Tier 1	1,025,772	829,293	777,401	487,613	341,588	168,505	161,796	179,351	205,481	427,790	663,580	949,734	6,217,904
Therms - Tier 2	1,025,772	829,293	777,401	487,613	341,588	168,505	161,796	179,351	205,481	427,790	663,580	949,734	6,217,904
Customers	163	161	160	159	158	157	156	154	153	152	151	150	156
Distribution Charge - Tier I	$0.205463	$0.205463	$0.205463	$0.205463	$0.205463	$0.205463	$0.205463	$0.205463	$0.205463	$0.205463	$0.205463	$0.205463	
Distribution Charge - Tier II	$0.184917	$0.184917	$0.184917	$0.184917	$0.184917	$0.184917	$0.184917	$0.184917	$0.184917	$0.184917	$0.184917	$0.184917	
Customer Charge	$170.00	$170.00	$170.00	$170.00	$170.00	$170.00	$170.00	$170.00	$170.00	$170.00	$170.00	$170.00	
TY 2024 Revenue	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Distribution Charge Revenue	$400,441	$323,739	$303,482	$190,354	$133,349	$65,781	$63,162	$70,015	$80,216	$167,000	$259,048	$370,757	$2,427,344
Customer Charge Revenue	$27,640	$27,439	$27,239	$27,038	$26,837	$26,636	$26,436	$26,235	$26,034	$25,833	$25,632	$25,432	$318,431
Distribution + Cust Chg Revenue	$428,081	$351,179	$330,720	$217,392	$160,186	$92,417	$89,598	$96,250	$106,250	$192,834	$284,681	$396,188	$2,745,775
CCRC Revenue @ 0.036669/therm	$75,229	$60,819	$57,013	$35,761	$25,052	$12,358	$11,866	$13,153	$15,070	$31,373	$48,666	$69,652	$456,011
Dist + Cust Chg Revenue w/o CCRC	$352,852	$290,359	$273,707	$181,631	$135,135	$80,059	$77,732	$83,096	$91,180	$161,460	$236,015	$326,536	$2,289,764
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
FRC - 2024	$2,170.20	$1,798.91	$1,708.24	$1,142.00	$856.01	$510.96	$499.87	$538.46	$595.40	$1,062.52	$1,565.30	$2,182.76	
FDC - 2024	$0.171994	$0.175065	$0.176040	$0.186245	$0.197804	$0.237558	$0.240215	$0.231659	$0.221869	$0.188714	$0.177834	$0.171909	

Revenue Decoupling Mechanism Model

Medium & Large Interruptible, Interruptible Transportation

TY 2024 Therms and Customers	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Therms	13,506,485	11,768,162	11,778,955	10,193,081	7,425,031	5,570,309	6,334,216	6,471,231	6,542,491	9,411,459	9,681,069	11,701,147	110,383,636
Customers	98	98	98	97	97	97	97	96	96	96	96	96	97
Distribution Charge - Medium Interruptible Tier I	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	
Distribution Charge - Medium Interruptible Tier II	$0.130831	$0.130831	$0.130831	$0.130831	$0.130831	$0.130831	$0.130831	$0.130831	$0.130831	$0.130831	$0.130831	$0.130831	
Distribution Charge - Large Interruptible Tier I	$0.130725	$0.130725	$0.130725	$0.130725	$0.130725	$0.130725	$0.130725	$0.130725	$0.130725	$0.130725	$0.130725	$0.130725	
Distribution Charge - Large Interruptible Tier II	$0.117653	$0.117653	$0.117653	$0.117653	$0.117653	$0.117653	$0.117653	$0.117653	$0.117653	$0.117653	$0.117653	$0.117653	
Distribution Charge - Interruptible Transport	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	$0.145368	
Customer Charge - Medium Interruptible	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	$300.00	
Customer Charge - Large Interruptible	$450.00	$450.00	$450.00	$450.00	$450.00	$450.00	$450.00	$450.00	$450.00	$450.00	$450.00	$450.00	
Customer Charge - Interruptible Transport	$325.00	$325.00	$325.00	$325.00	$325.00	$325.00	$325.00	$325.00	$325.00	$325.00	$325.00	$325.00	
Customer Charge - Large Interruptible Transport Generation	$475.00	$475.00	$475.00	$475.00	$475.00	$475.00	$475.00	$475.00	$475.00	$475.00	$475.00	$475.00	
TY 2024 Revenue	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Annual
Distribution Charge Revenue	$1,815,473	$1,564,671	$1,532,872	$1,326,310	$996,371	$745,533	$847,967	$865,065	$879,300	$1,265,626	$1,309,691	$1,578,025	$14,726,904
Customer Charge Revenue	$30,384	$30,317	$30,251	$30,185	$30,118	$30,052	$29,986	$29,919	$29,853	$29,787	$29,720	$29,654	$360,226
Distribution + Cust Chg Revenue	$1,845,857	$1,594,988	$1,563,123	$1,356,495	$1,026,489	$775,585	$877,952	$894,984	$909,153	$1,295,413	$1,339,411	$1,607,679	$15,087,130
CIP Exempt Therms	2,919,456	2,032,066	2,132,901	2,535,729	1,693,895	1,589,699	1,579,164	1,608,061	1,716,708	3,380,522	2,641,598	2,912,805	26,742,604
CCRC Related Therms	10,587,029	9,736,096	9,646,054	7,657,352	5,731,136	3,980,610	4,755,053	4,863,170	4,825,783	6,030,937	7,039,470	8,788,342	83,641,032
CCRC Rev @ 0.036669/therm	$388,218	$357,015	$353,713	$280,789	$210,156	$145,966	$174,364	$178,329	$176,958	$221,150	$258,132	$322,262	$3,067,052
Dist + Cust Chg Revenue w/o CCRC	$1,457,639	$1,237,973	$1,209,410	$1,075,706	$816,333	$629,619	$703,588	$716,656	$732,195	$1,074,263	$1,081,279	$1,285,417	$12,020,078

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
FRC - 2024	$14,869.48	$12,657.20	$12,393.18	$11,048.10	$8,403.28	$6,496.05	$7,275.81	$7,427.92	$7,606.42	$11,185.69	$11,284.72	$13,446.22
FDC - 2024	$0.107921	$0.105197	$0.102675	$0.105533	$0.109943	$0.113031	$0.111077	$0.110745	$0.111914	$0.114144	$0.111690	$0.109854